LOWER OIL PRICES AND THEIR IMPLICATIONS FOR ENERGY RESEARCH AND DEVELOPMENT POLICY

HEARING

BEFORE THE

SUBCOMMITTEE ON
ENERGY DEVELOPMENT AND APPLICATIONS

AND THE

SUBCOMMITTEE ON
ENERGY RESEARCH AND PRODUCTION

OF THE

COMMITTEE ON
SCIENCE AND TECHNOLOGY
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LOWER OIL PRICES AND THEIR IMPLICATIONS FOR ENERGY RESEARCH AND DEVELOPMENT POLICY

WEDNESDAY, JUNE 22, 1983

House of Representatives, Committee on Science and Technology, Subcommittee on Energy Development and Applications, and Subcommittee on Energy Research and Production,

Washington, D.C.

The subcommittees met, pursuant to call, at 9:30 a.m., in room 2318, Rayburn House Office Building, Hon. Don Fuqua (chairman of the Subcommittee on Energy Development and Applications) presiding.

Mr. Fuqua. The subcommittee will be in order.

Energy research and development policy has been, until recently, driven by the view that oil prices would continue their upward spiral unabated. Indeed, the committee heard many such scenarios from a number of respected analysts over the past several years.

It now appears, however, that many of these earlier forecasts were overly pessimistic. There is now a substantial number of analysts who believe that oil prices will remain reasonably stable, or even decline in real terms, for the remainder of this decade or longer.

Energy and economic projections will continue to influence the evolution of an effective U.S. energy research and development policy. A reexamination of forecasts in light of the expectation of lower world oil prices may lead to a significant reassessment of the proper role of the Federal Government in the energy research and development process. Such a reassessment, in turn, may impact the optimal funding levels of the various programs under the purview of these subcommittees.

In today's hearing, we hope to examine a number of issues surrounding such a reassessment:

One, what is the long-term prospect for oil prices?

Two, how have energy supply and demand and price projections changed in recent years and what are the principal factors accounting for changes?

Three, how are energy price projections, forecasts, and modeling used to assess the impacts of lower oil prices on energy research and development planning and programs; and

Four, what are the implications of lower oil prices on energy research and development?

Finally, we also want to explore the question of whether or not oil price projections are an appropriate basis for the development of energy research and development policy.

Today, we will hear from Government, industrial, and academic policymakers on these issues. I want to welcome all of you here today. We are looking forward to your testimony.

Mrs. Lloyd.

Mrs. LLOYD. Thank you very much, Mr. Chairman.

I have been concerned in the past about those who advocate using energy models that predict low energy growth rates, particularly electric energy growth rates. Implicit in these models is the almost total disconnect between economic growth and electrical energy use growth, contrary to a long history of close interaction. It seems a truism to me that if more factories are built producing more goods, then electricity must be available to these factories to run the equipment that will produce the goods.

If we base our energy policy on an assumption that we may not need more electricity for any reason and we are not in a position to produce more electricity if needed, then the price we pay is an inability to build those factories, and thus a stifling of economic growth and a potential decline in standards of living. The consequences of such a shortsighted policy are too great for the simple price today of planning to increase supplies of energy resources through enhancing the electrical option in the future.

The past administration had its faults in energy research and development planning in that it agonized over the "nuclear as a last resort" policy.

Nuclear energy is a potential resource of almost unlimited magnitude and should be available to augment society's power options for the good of mankind. The current administration has rectified the past administration's problem but has created similar problems in coal, synfuels, conservation, and solar research and development.

Both administrations have, therefore, contributed to a crisis of confidence in Government research and development programs by draconian cuts in energy budgets and extreme shifts in policy.

This crisis, felt by the private participants in the Government's programs, has justifiably been caused by a lack of dependability of our Government as a consistent partner in long-term energy development projects. This lack of Government continuity is attested to by its failure to complete any of the DOE fossil demonstration projects and the leisurely pace taken by the Synthetic Fuels Corporation in awarding projects.

Today, another symptom, that of complacency, is exacerbating the effects of the disease of policy uncertainty. We are all aware that the surplus of oil in the world today has lessened the urgency, and thus the commitment, for many in the executive and legislative branches as well as in the public sector for the development of alternative sources of energy. Considering that most energy experts agree that oil is a diminishing resource and that the current glut is temporary, research and development into the alternatives to oil utilization should remain a firm priority in the policy and budget of the United States.

It seems evident that one important treatment for this disease would be to formalize and enact a broad outline of a national energy plan which would tend to stabilize the focus of our long-term research and development programs so that they can survive changes in administrations. Regardless of where one comes out on the priorities for energy research and development, radical shifts in policy and funding are detrimental to technology development and are undermining the ability of the United States to prepare for its future.

I am looking forward to hearing what our distinguished witnesses will bring to the debate over what our energy research and development should be in light of lower or steady, rather than accelerating, oil prices. I welcome all of you here today before our two subcommittees.

Thank you, Mr. Chairman.

Mr. FUQUA. Thank you very much.

Our first panel of witnesses will be J. Erich Evered, Administrator of the Energy Information Administration; Jan W. Mares, Assistant Secretary for Fossil Fuel and Acting Director for Policy, Planning and Analysis; Dr. Alice M. Rivlin, Director of the Congressional Budget Office, and followed by Dr. Eric Willis, Director of Research for the International Energy Agency from France.

We are glad to have you here, sir.

We will begin with Mr. Evered.

STATEMENT OF J. ERICH EVERED, ADMINISTRATOR, ENERGY INFORMATION ADMINISTRATION, U.S. DEPARTMENT OF ENERGY

Mr. EVERED. Thank you, Mr. Chairman.

I am delighted to be here. This is my first opportunity to be before this committee and it is a pleasure to be here on the first full day of summer.

Mr. Chairman, I am pleased to appear before you and the committee to discuss recent energy projections by the Energy Information Administration and our thoughts on the use of models to make projections of energy markets.

The legislation that created the EIA vested it with an element of statutory independence. Acting under this charter, the projections that I am offering are the results of an objective, independent analysis—they do not purport to represent the policy positions of the Department of Energy or the administration.

One of my goals as administrator has been to simplify and reduce the cost of our forecasting efforts without sacrificing the usefulness of our product. To meet better our responsibilities for integrated forecasts, we have recently developed a smaller, more efficient modeling system, the intermediate future forecasting system, IFFS, to replace the complex and very labor-intensive midterm energy forecasting system that was developed in the midseventies.

Where the previous system generated forecasts for every fifth year—for example, 1985, 1990, 1995—the newer model is capable of generating projections year by year. At present, our projections extend to 1990.

World oil prices peaked in 1980 and 1981 at a price, in 1982 dollars, of $39 per barrel. Since that time, excess production in the oil exporting countries and reduced consumption caused by reaction to previous price increases and worldwide recession have resulted in a relatively soft oil market. Average world f.o.b. prices drifted down to $33 per barrel by the end of 1982 and $28 to $29 per barrel during the second quarter of 1983.

These recent changes in world oil markets are reflected in the three world oil price projections prepared by EIA for our recently released Annual Energy Outlook. For consistency and comparability, Mr. Chairman, all of the prices in our projections are stated in terms of 1982 dollars. Even in the high world oil price case, prices decline through 1984.

In the midprice case, the 1982 dollar price of oil declines until 1985, when it is projected to reach $25, before rising again. Our low price projection, based on relatively optimistic assessments of supply and slow growth in world consumption, reaches a minimum of $21 per barrel in 1985 and 1986, and rises thereafter. By 1990, the price projections range from $28 per barrel in the low case to $48 in the high—a substantial range of uncertainty.

Based on the world oil price paths, we prepared overall projections of domestic energy markets through 1990. Because the focus of this hearing is upon the effects of lower world oil prices, I will describe the projections based on the lowest of the three price projections.

Even in the low price case, the trends toward greater energy efficiency and lower per capita consumption are projected to continue. While the projected price of oil in this case falls to $21 in 1986, this price is still well above the price of $8, again in 1982 dollars, that prevailed in 1973. Since other energy prices are projected to increase, and the price of oil, while declining, is still high relative to historic levels, the incentive to conserve is not lost.

The second major finding concerns the relative price of oil products—particularly low sulfur residual fuel oil—and of natural gas. By 1985, EIA projects that the cost of low sulfur residual fuel oil may be less than the price of natural gas in the utility market. This is true in our analysis for both mid- and low-oil price path cases. Many utilities and large industrial users have plants capable of burning either gas or low sulfur fuel oil. We estimate that, if oil prices are as low as our projections assume, up to 1.5 million barrels per day of switching to oil could occur—depending on the price of natural gas.

This result, I want to emphasize, is dependent upon the price of natural gas. The price projection used in this study is based on the assumption that the Natural Gas Policy Act is not modified and that little or no renegotiation of natural gas contracts will take place. As a result of these assumptions, projected natural gas prices would rise sharply in 1985, precisely when projected oil prices are reaching a minimum. It is logical to assume that lower gas prices, for example, would reduce the amount of switching to oil.

These technical details in our analysis are important to point out because of their potential impact on oil imports. While some increase in oil imports is to be expected as the economy grows, in our low world oil price case, projected imports are 8.7 million barrels per day in 1985 and 9.5 million barrels per day in 1990. This compares to 4.2 million barrels per day actually imported in 1982, Mr. Chairman.

Should our assumptions pointed out above prove wrong, imports could be lower—perhaps significantly lower. Security of oil is a complex topic that we cannot explore completely in this hearing.

The price advantage projected for oil does not, however, extend over coal or nuclear power. As coal and nuclear powerplants currently under construction come online, the share of domestic energy production from these sources is projected to increase. By 1990, nuclear power is projected to amount to about 20 percent of electric power generation, while coal is projected to continue to supply over half of the electricity used in the United States.

From a long-term perspective, the decline in oil prices is likely to be temporary. All three of our world oil price projections are rising by 1990. Indeed, the midprice projection is $37 per barrel in 1990, close to the price of 2 years ago. The price increases of the late 1980's would be expected to continue through the 1990's.

This implies that the date at which the various technologies now under development would become attractive may be delayed by the recent declines in the world oil price, perhaps by 5 to 10 years, but it does not mean that the long-term attractiveness of alternative sources of energy has changed. As conventional sources of supply become more difficult to find and more expensive to exploit, the desirability of new energy sources will increase.

EIA does not currently prepare long-term forecasts beyond 1990. We do, however, catalog and compare forecasts prepared by others. Our reasons for using these forecasts are simple and straightforward. Forecasting the future is, of course, uncertain. The uncertainty increases the further you look into the future. Given the inherent uncertainties of long-term forecasting, we have concentrated our efforts on improvements to our projections of energy markets over the short-to-medium term. It is in this area that we feel we can make the most useful contribution toward understanding the forces at work in energy markets and the direction in which these markets are changing.

The uncertainty of forecasts increases with the length of time over which one is trying to project. Reasonably accurate short-term projections can be obtained by extrapolation of trends; that is, today's prices and quantities are reasonably good predictors of tomorrow's prices and quantities.

As the time period projected recedes into the future, however, the likelihood of important events unanticipated at the time of the forecast increases and the potential cumulative effect of these events compounds. Few, if any, projections of U.S. electricity demand prepared in 1963 would have correctly anticipated the extent to which growth in electricity demand has slowed down in the United States.

In short, projections of energy markets 20 years hence are unlikely to strike anywhere near the actual values.

That does not mean that long-term forecasts are without virtue—they provide a framework for discussion of the future which lets one see the direction, if not the magnitudes, of the effects of some change in policy or new development in the world. Through the use of a formal model, one can enforce consistency in thinking about the outcomes of possible events. Properly used, it forces the analyst to take account of interrelationships among fuels and between the energy sector and the general economy.

Models can assist a policymaker by:

One, helping him think through a set of options systematically.

Two, identifying critical points or decision points for possible policy action.

Three, identifying robust aspects of policies or energy/economy systems with respect to key uncertainties.

Four, providing fairly specific estimates of the outcomes that would result from alternative decisions.

Nevertheless, the degree of uncertainty surrounding the results is very large indeed.

Let me show you the way in which EIA's forecasts of domestic gross energy consumption and of oil consumption for 1990 have changed over the last 6 years. I refer you, Mr. Chairman, to page 7 of my prepared testimony.

Over this period, our projection of gross energy consumption in 1990 has declined by nearly 25 percent. Our oil consumption projection have varied even more—the 1979 projection for 1990 is only two-thirds of the projection prepared 2 years earlier. Although our most recent oil consumption projection is somewhat higher than the 1979 projection, it is far below earlier forecasts.

A large part of these differences lies in assumptions made for the earlier efforts that were invalidated by subsequent events such as the oil price increases in 1979. In any case, the overall direction of change is clearly downward over the six forecasts. I would like to think that this reflects increased understanding of forces at work in energy markets.

We are aware that the requirements for long-range forecasting can be important. We believe that the approach we are now taking at EIA to fulfill our obligations with respect to long-range forecasting is practical, useful, and productive. We will take an openminded approach to all of those forecasts, recognizing that they are inherently uncertain and subject to change. We intend to scrutinize these estimates to assure ourselves that they are realistic, but we do not think it would be productive to duplicate their efforts and risk deceiving you or ourselves that we could come up with completely definitive data.

I would be glad to respond to any questions you may have.

[The prepared statement of Mr. Evered follows:]

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System that was developed in the mid 1970's. Where the previous system generated forecasts for every fifth year (e.g., 1985, 1990, 1995) the newer model is capable of generating projections year by year. At present our projections extend to 1990.

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The price advantage projected for oil does not, however, extend over coal or nuclear power. As coal and nuclear powerplants currently under construction come on line, the share of domestic energy production from these sources is projected to increase. By 1990, nuclear power is projected to amount to about 20 percent of electric power generation, while coal is projected to continue to supply over half of the electricity used in the United States.

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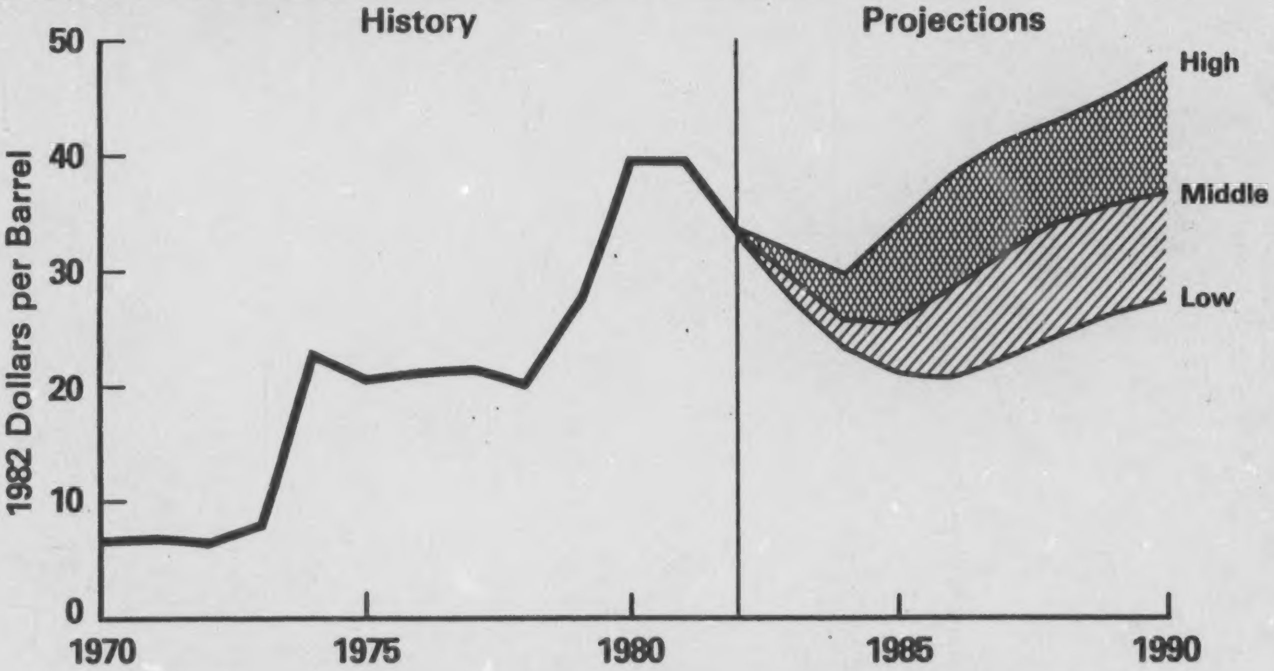
I would be glad to respond to any questions you may have.

World Oil Price Projections, High, Middle, and Low World Oil Price Scenarios, 1970 to 1990

(1982 Dollars per Barrel)



Note: All prices reflect the average landed price of crude oil in the United States.

Source: Energy Information Administration.

Mr. **Fuqua**. Thank you very much, Mr. Evered.

We will defer the questions until all of the panel has completed their testimony and then we will have questions for all of you.

Mr. Mares.

[The biographical sketch of Mr. Mares follows:]

U.S. Department of Energy
Assistant Secretary for
Congressional, Intergovernmental
and Public Affairs
Office of Public Affairs
Washington, D.C. 20585
202/252-5644

BIOGRAPHY

JAN W. MARES

Jan W. Mares is Assistant Secretary for Fossil Energy for the U.S. Department of Energy (DOE). In this position, Mr. Mares' major responsibilities include research and development related to coal, petroleum, oil shale and natural gas resources. In addition to his Fossil Energy duties, Mr. Mares has served as DOE's Acting Under Secretary from June 29, 1982 until December 16, 1982, and is currently serving as the Acting Director of the Department's Office of Policy, Planning and Analysis.

Prior to Federal service, Mr. Mares was with Union Carbide Corporation, having joined that organization in 1963 as an attorney in the Law Department. He was subsequently assigned to positions involving the domestic chemicals business, the Finance Department, and various Union Carbide foreign activities before he was appointed International Counsel in 1972. In 1973, he became business manager in the Hydrocarbons Department, responsible for an effort to develop a petrochemical project with an oil-producing country. Following that appointment, he held various line and staff assignments in the chemicals area. From the first part of 1980 until joining DOE, he was vice-president/general manager of the Ethylene Oxide Derivatives Division.

He is an alumnus of Harvard College where he received a B.A. degree in chemistry in 1958. He also holds a M.S. degree in chemical engineering from Massachusetts Institute of Technology, received in 1960, and a L.L.B. degree from Harvard Law School, received in 1963.

Mr. Mares is a member of the American Chemical Society, the American Institute of Chemical Engineers, the Society of Petroleum Engineers, the American Bar Association and the New York State Bar Association.

He was born in St. Louis, Missouri and attended schools in Missouri and Texas. Mr. Mares is married to the former Lois Haase and they have two children.

May, 1983

STATEMENT OF JAN W. MARES, ASSISTANT SECRETARY FOR FOSSIL ENERGY AND ACTING DIRECTOR FOR POLICY, PLANNING AND ANALYSIS, U.S. DEPARTMENT OF ENERGY

Mr. **Mares**. Thank you, Mr. Chairman.

I would like to submit my formal statement for the record.

Mr. **Fuqua**. Without objection, we will make that part of the record.

Mr. **Mares**. I will summarize its key points and briefly tie the subject of the hearing into the energy policy of our Department.

The energy policy of this administration is straightforward. We want an adequate supply of energy at a reasonable price for this country. We believe that the strategy involves two fundamental principles. First, to rely on the private sector as much as possible to do what it can do best; and secondly, we should continue to support a balanced and diversified energy R&D program.

I want to emphasize that one of the reasons the administration stresses a reliance on market factors to solve our energy and economic problems is that the market allows for this diversity. It does not straightjacket the economy to one approach or one set of assumptions. The private sector is free to invest in the future as they individually see fit. Of course, most commercialization decisions are based on projections for future market conditions, generally on the forecasted price of competing products. In energy, this means principally world oil.

The Energy Department's policy is to provide projections. In the testimony we have presented the preliminary numbers from the National Energy Policy Plan, which will be submitted to Congress at the end of July. For 1990, we project a range of prices in 1982 dollars of $26 to $40 per barrel. This compares to a $55 mid-range price in the NEPP-1981 document and a $29 mid-range price in the NEP-1979 document. Those can be seen in figure 1 on page A-5 of the testimony.

For the year 2000, we project a range of $36 to $80 a barrel whereas in NEPP-1981, a $74 barrel was projected in mid-range and $41 in NEP-1979.

Finally, in the year 2010, we project a range of $55 to $110 a barrel.

The projections for the year 2010 were not made either in 1981 or in 1979.

We have also included in our appendices a discussion of the recently released entitled "The Future of Electric Power in America", electricity policy report, which indicates a growing need for new powerplants to meet the long-term increasing demand and replace physically and economically obsolete plants.

There are a variety of other projections which we have heard about earlier this morning. All of these projections should be considered in the development of forecasts for the future. Our projections of the future of energy prices are probably as good as any, although I should point out that the record of government forecasts as well as non-government forecasts of energy prices has not been very good in the last ten years.

What are the reasons? In part, because they are derived from models which are mathematical equations based on a given set of assumptions. As good as the models are, there are limits on how well they can predict the future. All models are based on assumptions, assumptions of economic growth—assumptions of future international events, assumptions of technological processes and progress, and assumptions of interrelationships of those factors and others. The assumptions drive the results—both the assumptions that are used within the model and the assumptions that are used to build the model.

Uncertainty is inherent in the assumptions and this is compounded the farther one looks into the future.

Let me now turn specifically to energy research and development. The first chart which I have here is described on page 2 of my formal statement. Mr. Chairman, you have seen this in my budget presentation, but I think it sets the stage for discussion today.

We have divided the technological development path into five categories. Some people would call the basic science category basic research. The definitions of each category are in my testimony on page 3. In the later stages, process development and commercialization, the projects are much larger scale and more expensive. Finally, commercialization is self-evident. The costs associated with each stage increase exponentially.

As we attempt to integrate our overall energy goal, namely to provide the adequate energy supply at reasonable prices, to our R&D strategy, we have recognized that process development and commercialization is where industry is most comfortable, where it has not been reluctant in the past to invest its own funds with the prospects for substantial return, where the risks are principally associated with scale, economic viability, environmental performance, where the selection of promising concepts is based on market factors including institutional and regulatory consideration, as well as geographical factors and public acceptance.

The Government has historically not been proficient in making these types of decisions. The Government's response time to changing marketing conditions is not rapid. Its ability to decide that investments have been misdirected and change course accordingly is neither done quickly nor efficiently nor easily.

I think the Government, however, can play a very valid and important role in the earlier stages of research where there is a very high benefit-to-cost ratio from a national perspective, where the ultimate benefits may be quite large but they are difficult to predict, highly risky, long term, expensive to obtain, and cannot be captured by individual firms. Therefore, these stages of development attract little in the way of private investment.

I think the value of Government research in this area was illustrated in an excellent article in the February 18, 1983 issue of Science magazine which I would like to enter into the record. It is entitled "Industrial Innovation Policy, Lessons from American History."

[Attached for the record is a copy of the article from the February 18, 1983 issue of Science magazine entitled "Industrial Innovation Policy: Lessons from American History."]

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Industrial Innovation Policy: Lessons from American History

Richard R. Nelson and Richard N. Langlois

Summary. The historical interrelations of government support of R & D and technical change in seven major American industries point to three types of policy that have been successful in the past: (i) government R & D support for technologies in which the government has a strong and direct procurement interest; (ii) decentralized systems of government-supported research in the "generic" area between the basic and the applied; and (iii) a decentralized system of clientele-oriented support for applied R & D. A fourth type of policy, under which the government attempts to "pick winners" in commercial applied R & D, has been a clear-cut failure.

Government involvement in the research and development (R & D) process has a long history in this country. As is too often the case, this rich experience has seldom been consulted in policy debates over government programs to stimulate industrial innovation.

This article is an attempt to identify some of the lessons of past federal R & D policy. It summarizes the conclusions of a study, recently completed at the Center for Science and Technology Policy at New York University, of how such policies have shaped technological change in seven major American industries—semiconductors, computers, aircraft, pharmaceuticals, agriculture, residential construction, and automobiles (*1*). What makes this study unique is its explicitly comparative, cross-industry focus: it was predicated on the hypothesis—amply supported in the resulting case studies—that the kinds of government programs that have shown themselves feasible and effective vary greatly among industrial sectors, depending upon the nature of the governmental involvement and the nature of competition in the industry.

The selection of industries for study was made with an eye toward obtaining a sample with a broad spectrum of characteristics: industries with fragmented as well as with concentrated structures and industries subject to much government intervention and to relatively little. The design of the study was also informed by a desire to attract recognized scholars knowledgeable about the technology in each industry; the prior interests and areas of expertise of these scholars were therefore a factor in the selection of industries. The study was then carried out as a cooperative research effort (*2*).

The Unraveling Consensus

In treating the questions of innovation policy as warranting detailed empirical exploration, we were acknowledging, reluctantly, that the general theoretical analyses and statistical observations of economists provide only limited and incomplete guidance for policy. We are not alone in this perception; the most significant aspect of the recent economic literature on innovation is its progressive inconclusiveness about the appropriate role for government.

It was not always that way. Economic research a decade or more ago had settled on two closely related sets of propositions about industrial innovation. The first of these was that technological change is an important source of productivity growth and, simultaneously, that R & D expenditure is a principal determinant of technological advance. The implication drawn from this was that R & D spending is a kind of "control variable" through which one would affect macroeconomic productivity.

The second set of arguments derived from theoretical rather than statistical work. Economists during the 1950's and '60's developed models in which private firms possessed an inherent tendency to

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The authors are, respectively, a professor of economics at Yale University, New Haven, Connecticut 06520, and a research assistant professor in the Center for Science and Technology Policy, Graduate School of Business Administration, New York University, New York 10006.

"underinvest" in R & D. There were several reasons for this unhappy circumstance: (i) R & D creates knowledge, and knowledge is a "public good" in the sense that the firm cannot fully appropriate to itself the benefits of the knowledge it creates (*3*); (ii) the payoff to R & D is uncertain, and risk-averse firms will therefore wish to do less of it than a (risk-neutral) society would prefer (*4*); and (iii) the fragmented structure of certain industries militates against sufficient R & D spending, the firms being too small to undertake certain kinds of projects (*5*).

Taken together, these sets of arguments strongly supported the notion that the government's role lay in correcting a global problem of inadequate private R & D. But over the last decade the consensus surrounding this conclusion has essentially come undone.

First, and perhaps most important, the experience of the 1970's cast doubt on the presumed tight link between a nation's overall R & D spending and its rate of productivity growth. Although it is true that high rates of R & D spending attended the rapid growth of productivity in the United States, Western Europe, and Japan during the 1950's and '60's, spending for R & D continued to be high in most countries during the ubiquitous slowdown in productivity growth after 1973. Only in the United States and France was the slowdown presaged by a decrease in R & D expenditures, and in both those countries the decrease was almost exclusively in defense and space rather than in civilian areas. Moreover, recent studies of the differences in productivity growth among countries suggests that, even in the 1950's and '60's, the countries with the highest ratio of R & D spending to gross national product—the United States and Britain—had among the lowest rates of productivity growth (*6*).

Part of the message seems to be that it matters where a country is relative to the frontier of technology and productivity. Countries not on the frontier can "play catch up" fairly easily without much R & D spending so long as their rates of physical investment are high. Countries nearer the frontier have to work harder for each percent increase in productivity. This begins to suggest that it is not necessarily to a country's great advantage to be alone on the frontier. There is evidence that, as before World War II, the United States is again benefiting from technological ideas developed elsewhere; and there may be much to recommend a world in which many countries share the technological frontier and therefore share a common economic environment in an interdependent way (*7*).

At the theoretical level, many economists have also begun to believe that the relation between competition and innovative behavior is more than a matter of some tendency to "underinvest" (or even to "overinvest") in R & D. The relationships of innovation to information "externalities," to risk, and to market structure are increasingly seen to be subtle and complex (*8*, *9*).

In the first place, the implications for total R & D spending of imperfect appropriability are now understood to be less clear-cut than they once seemed. Economists are coming to realize that, in a world of patents and industrial secrecy, firms in some instances have an incentive to engage in duplicative or near-duplicative R & D in an effort to copy a rival's technology or "invent around" its patents. This at once calls into question the idea that firms necessarily engage in too little R & D; more important, it begins to focus our attention not on the level of R & D but on the types of R & D projects the industry engages in.

The economist's view of the "uncertainty" issues had taken a similar turn. Rather than focusing on the amount of R & D that uncertainty is likely to draw forth, economists are now recognizing that what uncertainty really demands is the exploration of a diverse set of approaches. This way of looking at things suggests that heavy commitments to any one approach are dangerous in the early stages of development of a technology and should be avoided until the uncertainties (both market uncertainties and technological ones) are significantly reduced.

What that suggests in turn is that the focus of the policy issue should shift from R & D levels to the portfolio of R & D projects an industry tends to generate. This entails turning our attention toward the incentive effects of policies and institutional structures and toward considerations of access, secrecy, and information flow. In practice, some kinds of R & D projects will tend to be "underfunded" and some to be "overfunded"; and a simple R & D subsidy is not the sort of policy such a situation demands.

The Case Study Approach

Although many economists are exploring new approaches to the theory of innovation and technical change, analyzing the effects of government policy on industrial innovation must still be seen as largely an empirical problem—which policies have worked, which have not, and why. This was the premise behind our seven industry case studies. One conclusion, which we develop below, is that what the government can do effectively differs from industry to industry. There are nevertheless certain features common to technological change in all industries that should be kept clearly in mind in designing government policies.

One theme that unites the history of technological change is the pervasiveness of uncertainty. Although it takes a form in (say) the pharmaceutical industry very different from that in the commercial aircraft industry, uncertainty seems nevertheless to be endemic. A quick reading of the case studies is enough to dash any supposition that technological change is somehow a cleanly plannable activity. In fact, it is an activity characterized as much by false starts, missed opportunities, and lucky breaks as by brilliant insights and clever strategic decisions. Only in hindsight does the right approach seem obvious; before the fact, it is far from clear which of a bewildering array of options will prove most fruitful or even feasible. Strange as it now seems to us, aviation experts were once divided on the relative merits of the turboprop and turbojet engines as power plants for the aircraft of the future; and the computer industry was by no means unanimous that transistors—or, later, integrated circuits—were to be the technology of the future. Policy must recognize uncertainty as a fact of life, and must not try to repress it or analyze it away.

A second and related universal theme is the importance of detailed knowledge of the technology, of its strengths and weaknesses, and of user needs in guiding the innovation process. In all the case studies, either the producer-provider or the user-demander played a major role in generating and screening technological advances. Whenever major innovation was attempted without access to their knowledge, the results were disastrous. This fact imposes severe constraints on what government can do effectively.

The implications become clear if we consider four general kinds of government support for civilian R & D: (i) programs attendant on government procurement or some other well-defined public objective; (ii) programs to support research on "generic" technologies—research in the gray area between basic scientific research and applied R & D; (iii) programs to support applied R & D in the service of well-defined clientele demands; (iv) programs that insist on "picking winners" in commercial applied R & D. Programs of each sort show up in several guises in the industry case studies.

Procurement-Related R & D

In three of the industries studied—aviation, computers, and semiconductors—the government was heavily involved as a user-demander of the technology. This kind of government involvement has two important policy implications.

The first has to do with the ability of the government to guide R & D effectively. In cases of government procurement for defense, space, or similar clearly defined public projects, the government is itself the user-demander. It thus has knowledge of its own needs and, usually, at least a modicum of expertise in the technology it proposes to use. Motivation and knowledge line up fairly well in such circumstances, and the government is frequently able to sponsor effective R & D on the relevant technology. To the extent that the technology can be easily transferred to commercial application, the result is the well-known "spillover" into civilian technology.

Second, a public belief in the legitimacy of the government's primary mission—defense, for example—smooths the political waters for any related program of government R & D support. In the semiconductor industry the Department of Defense and the National Aeronautics and Space Administration (NASA) played a crucial role. Both the transistor itself and the integrated circuit were first developed with private funds; but, in the latter case at least, military and space demand was certainly an important motivation, and once those innovations were clearly identified, government support of product and process engineering helped speed their advance. Similarly, the government funded much of the early research, and provided much of the early market, for the digital computer. Defense procurement and in recent years heavy government R & D funding have played a major role in the evolution of aircraft technology.

It is important to recognize that the efficacy of government procurement-related R & D depends on the knowledge-advantage that comes from the government's position as user and on the political legitimacy of its mission as justified on grounds other than spillover benefits. The conclusion thus does not extend to government procurement projects, the justification of which is the spillover itself or in which the procurement is intended to make a market for the technology. [The supersonic transport (SST) project remains the best case in point.]

Moreover, our case studies suggest that the potential for the generation of spillover by procurement-related government R & D support may be limited to the early stages of a technology's development, when government and civilian demands are not yet specialized. As a technology matures, the requirements of the government and the private sector normally diverge. This means not only that spillover diminishes but also that military and commercial R & D increasingly compete for resources. In the mature phases of a technology's development, spillover may be as much to the military from the commercial sector as the other way round.

Generic Technologies

When there is no recognized public-sector demand for a technology, the government's ability to fund R & D effectively and to guide the development of that technology is more limited. The government does not then have natural access to the sorts of information necessary to guide allocation, and may in fact be blocked from getting the information. Furthermore, the legitimizing effect of a public sector purpose is not there to protect a support program from strong political opposition.

Nonetheless, these problems may be attenuated if the government restricts its attentions to areas, such as so-called generic technology, that are a step or two removed from specific commercial application. The reason is that, at this "directed basic" level of research, the knowledge involved has a large public component: much of it is the sort of nonpatentable and nonspecific knowledge—broad design concepts, properties of materials, and testing concepts—that is generally shared among scientists and does not pose a strong threat to proprietary interests.

In a sense, such generic work falls in between the sorts of work that an academic researcher, pursuing fashionable questions within the bounds of a standard scientific field, would tackle and the kinds of result-oriented research that would interest most corporate R & D laboratories. Of course, some companies do support generic research, and the findings are very often treated as public rather than as proprietary. In many instances, the funding for such research comes at least in part from governmental sources. In either case, the keys to success seem to be, first, involving the relevant scientific and technical communities in the allocation process and, second, recognizing that research ought to be influenced both by the purely scientific disciplines and by those interested in applications; indeed, a tension between the pure and the applied is generally salutary.

Our case studies provide examples of generic research, some associated with government procurement (in aviation, computers, semiconductors) and some more commercially oriented work (certain aspects of agricultural and pharmaceutical science).

The agricultural sciences, viewed as a generic research system, seem to have defined and filled their niche appropriately. Such work fits in between the academic basic sciences (like chemistry and biology) and the applied R & D carried out in private firms and in the experiment stations (like the development of new seeds or fertilizers). Interests on both sides of the line pull and tug to influence the kinds of research that are done as well as to monitor its quality and efficacy. The biomedical research community is another example. Research here too is pulled by applied interests (the physicians) and tugged by scientists in the more basic fields. Interestingly, both the agricultural and the biomedical sciences typically reside in university settings, but in separate professional schools rather than main-line departments.

Another similarity between agricultural science and biomedical research is the way funding allocation is carried out. Both disciplines take the majority of their support from the government, but the funding agencies keep their distance, allowing the allocation machinery to be manipulated by the research communities themselves.

The National Advisory Committee on Aeronautics (NACA), the forerunner of NASA, is another example of a generic research system. Here the setting was a freestanding organization, not a university. But NACA's research concerns were certainly generic—broad-gauged aviation problems rather than specific designs—and the relevant engineering societies played a significant role in guiding and monitoring work at NACA. After World War II, the military increasingly assigned to private contractors the sort of work NACA had carried out, a trend that both reflected and abetted the divergence of military from civilian aircraft technology.

Because generic research poses a diffuse rather than a visible threat to established competitive positions, it may be possible to mount such a program successfully in any industry. But the size of the gray area between the basic and the applied may vary greatly among industries. Of course, the extent of this generic range may itself be influenced by the presence of a government program: the public financing of R & D often proves contagious, luring business scientists into a wider communications network and increasing the public flavor of private work. This is certainly desirable to the extent that it does not diminish the private incentive or ability to seize upon new ideas and develop them for market.

The manner in which a generic program develops may also be of critical importance. The aborted Cooperative Automotive Research Program (CARP) and the Cooperative Generic Technologies Program (COGENT) of the last administration seem to fit the description of generic systems, yet neither attracted the enthusiasm of the industries it proposed to aid, perhaps because the initiative and the design of the programs came strictly from Washington, with little participation by industry.

Clientele-Oriented Applied R & D

The most important characteristic of government support for basic and generic research is that it does not require government administrators to make decisions that involve considerations of profitability and commercial potential. A basic or generic research program seeks to advance scientific and technical knowledge, and the decisions involved require primarily scientific and technical knowledge. While acquiring this sort of knowledge is not a trivial matter, it can at least conceivably be marshaled by program administrators, especially since the relevant scientific community can often be enlisted to help guide allocation. Moreover, basic and generic research, which involves exploring widely applicable technological options, seldom poses a concentrated threat to proprietary interests.

When we move closer to the level of applied research, however, the problems of government involvement multiply. The knowledge involved is both specific and idiosyncratic in form and may be proprietary in character. This instantly puts the government administrator at an informational disadvantage vis-à-vis firms that have no incentive, and sometimes no ability, to transmit what they know to Washington. Moreover, it is difficult to maintain a political constituency for a program that poses visible threats to established competitive positions.

Now, there is one much-discussed example of a strikingly successful government program of applied R & D: the agricultural research system. As noted above, much of the research supported in this program has been basic and generic, but a sizable proportion has been extremely applied in character, focusing on particular objectives like better seed varieties or more effective pest control. The interesting question is: what special conditions have made this applied R & D program feasible and productive?

A crucial feature of the agricultural industry is that it is largely atomistic in form. The competition among farms is something near to the "perfect competition" described in economics textbooks rather than the more rivalrous kind that characterizes most manufacturing industries. For this reason, fellow competitors are seen as inherently less threatening in farming than in most other industries; technological knowledge is therefore far less proprietary, and there is a public cast to the results of even very applied R & D.

The federal-state system of agricultural experiment stations evolved in a way that took advantage of the market structure in agriculture, marshaling the support of the farmers and giving them an important position in the evaluation and selection of projects. Coupled with the regional nature of agricultural technology, this led to a system in which farmers see it as advantageous to them to advance even very specific technologies as quickly as possible. As a model for the administration of a government-supported applied R & D program, the agricultural system is quite instructive. It is highly decentralized, and specific resource allocation decisions are made at state and county levels. Those decisions respond with some sensitivity to the demands of two constituencies: farmers (given voice through state legislatures) and the agricultural science community.

In the language of the social scientist, we might call this a "captured" system, in much the same sense that transportation, communication, and other industries are said to have captured their regulators. Capture of this sort is not very often congruent with the general interest of consumers; but in the case of agriculture the system seems to have evolved in a salutary fashion.

The residential construction industry is also relatively atomistic in structure, and has therefore long been seen as conformable to the agricultural model. Yet several government efforts to spur housing R & D have not worked; more accurately, the housing industry beat back or cut back the government attempts to mount such programs.

There are probably many reasons for the nontransferability of the agricultural model to housing. Building is somewhat more rivalrous in character than farming, at least at the level of materials suppliers. More important, the atomistic home builder is very likely more conscious of a threat from housing innovation than is (or was) his atomistic counterpart in farming. Although agricultural innovation did in the long run lead to the demise of the small farmer by increasing the scale of farming operations, each small farmer could nonetheless see the benefit to him (in the short and medium run, at least) of improved farming methods. The builder may well be more aware that any exploitation of scale economies brought about by innovation would very likely redound to his disadvantage, posing a clear threat to the system of small local firms in which he operates. Another factor is that building codes—a very old form of "new social regulation"—are intractable and entrenched. And there is not the background of good basic science in housing that there is in agriculture.

Beyond that, however, it may have been crucial that the agricultural research system evolved slowly over time and was not constructed de novo or centrally designed. It may even be that its success derives critically from the particular path the system's development followed (for example, its growth out of what was essentially a training program for farmers) and particular historical circumstances (such as the characteristics of the 19th-century industry) that are not easily replicated.

Picking Winners

Which brings us to the final approach to government R & D support—"picking winners" in commercial competition. Here the historical record seems, for a change, unequivocal. Unequivocally negative.

The SST project and Operation Breakthrough were two examples touched upon in our case studies. In both cases, the government did not attempt to create a framework in which scientific and user interests could guide allocation; rather, the federal agencies attempted to insert themselves directly into the business of developing particular technologies for a commercial market in which they had little or no procurement interest.

In the case of Operation Breakthrough, the Department of Housing and Urban Development had been neither a major builder nor a buyer of nonsubsidized housing. It had neither the technical expertise nor the market experience that commercial success demands. Similarly, the government was not in the business of making or buying commercial airplanes; those who were, the commercial aircraft companies, showed little interest in such a plane until the prospects for high subsidies appeared. Very few of the housing designs that came out of Operation Breakthrough have since had any commercial value; and the lesson from the British-French Concorde experience is that we are lucky we went no further than we did with plans for an American SST.

The lesson here is not specific to these cases; it is not that these particular government agencies lacked some necessary expertise that could in principle have been remedied by hiring a larger or better cadre of experts. The lesson is a general one, about the location of knowledge and the mechanism of its transmission in the R & D system.

European experience testifies to the generality of the lesson (*10*). In many cases, government attempts to enter the business of commercial applied R & D led to (i) duplicating private efforts or (ii) subsidizing those efforts and thereby replacing private with public funds or (iii) investing in designs the private sector had long abandoned as unpromising. There is certainly an argument that the government can be more forward looking than a private firm, supporting projects that are unpromising today but may be promising tomorrow. But the most effective way to perform such a next-generation function is not by competing in the commercial marketplace but through research of a more generic sort.

Lessons for Policy

The conclusions of a comparative historical analysis can only be qualitative and judgmental. But perhaps the lesson of economic theory and political practice during the last couple of decades is precisely the importance of this sort of empirical analysis.

Our central conclusion might be summed up in one word: complexity. The wide diversity of technological and institutional details, of knowledge structures and incentive structures, among American industries recommends against an industrial policy to boost "industrial innovation" in some global sense in the hope of affecting macroeconomic problems. Broad-brush measures like tax policy, antitrust policy, and patent policy, which affect each of the various industries in a very different way, should be assessed on their own merits and should not be viewed as "control variables" to stimulate innovation.

We do not propose a general rationale or justification for active government support of R & D. Applying the lessons of history to create programs that are both politically viable and socially desirable is no straightforward task. But the historical experience we have examined reveals three approaches that have worked in the past: support associated with government procurement or some other well-defined public sector objective; support of defined nonproprietary research, with allocation funds guided by the appropriate scientific community; and provision of an institutional structure that allows potential users to guide the allocation of applied R & D funds.

A fourth kind of policy, whereby government officials themselves try to identify projects that will be winners in a commercial market competition, is always seductive, but the evidence, from our studies and others, suggests that such strategy is to be avoided.

References and Notes

1. R. R. Nelson, Ed., *Government and Technical Change: A Cross-Industry Analysis* (Pergamon, New York, 1982). The authors responsible for the industry studies are: agriculture, Robert Evenson, Yale University; automobiles, Lawrence J. White, New York University; commercial aviation, David Mowery and Nathan Rosenberg, Stanford University; computers, Barbara Katz, New York University, and Almarin Phillips, University of Pennsylvania; housing, John Quigley, University of California, Berkeley; pharmaceuticals, Henry Grabowski and John Vernon, Duke University; and semiconductors, Richard Levin, Yale University. The study was supported by grant NSG7636 from the National Aeronautics and Space Administration.
2. Each author (or pair of authors) was responsible for an individual chapter, but the group agreed on a common format for the cases, and it met several times (sometimes with other scholars and representatives from government and industry) to discuss and integrate the chapters. R. Nelson was responsible for a synthetic "cross-cutting" chapter, which was in turn discussed and commented upon by the group.
3. The most influential of these models was by Kenneth Arrow [K. Arrow, "The allocation of resources to invention," in *The Rate and Direction of Inventive Activity: Economic and Social Factors*, R. R. Nelson, Ed. (Princeton Univ. Press, Princeton, N.J., 1962)]. But see also H. Demsetz, "Information and efficiency: Another view," *J. Law Econ.* 12, 1 (1969).
4. K. Arrow and R. Lind, "Uncertainty and the evaluation of public investment," *Am. Econ. Rev.* 60 (No. 3), 364 (1970).
5. The notion that "competitive"—that is, atomistic—firms innovate less than larger, "oligopolistic" firms has been called the Schumpeterian hypothesis, since those who read the work of Joseph Schumpeter through a certain set of spectacles discerned an argument of this sort in his *Capitalism, Socialism, and Democracy* (Harper, New York, 1942). The argument was stripped down to a more elemental form and popularized by John Kenneth Galbraith, especially in his *The New Industrial State* (Houghton-Mifflin, Boston, 1967).
6. Organization for Economic Cooperation and Development, *Technical Change and Economic Progress* (Organization for Economic Cooperation and Development, Paris, 1980). It may be significant that both the United States and Britain devoted an unusually high fraction of R & D to defense. But even when differences in defense R & D spending are accounted for, intercountry differentials in productivity growth seem better correlated with such matters as physical investment than with overall R & D spending.
7. N. Rosenberg, "U.S. technological leadership and foreign competition: 'De te fabula narratur?' " (photocopy, Stanford University, November 1981).
8. R. R. Nelson and S. Winter, "In search of a useful theory of innovation," *Res. Policy* 6, 36 (1977).
9. R. R. Nelson, "Research on productivity growth and productivity differences: Dead ends and new departures," *J. Econ. Lit.* 19, 1029 (1981).
10. See generally K. Pavitt and W. Walker, "Government policies toward industrial innovation: A review," *Res. Policy* 5 (No. 1) (1976).

Mr. **Mares**. As I have described on pages 6 and 7 of my testimony, the Government is not the principal customer of R&D products. Moreover, where it is viewed as a competitor to private initiatives, Federal R&D has historically not been productive. The view of the author, we believe, holds true for energy R&D, as well. We, the Government, are not going to be the ultimate customer for energy technology and if we, the Government, move too far into the process development and commercialization stages of the development process, we, in essence, become a competitor for the private sector. This deters individuals that are not selected for Government projects from proceeding and, in effect, subverts the market process.

We think Government funding has been most useful in the generic areas of research, basic science, applied research and in some proof-of-concept areas. The basic science and applied research activities through proof of concept should be our principal areas of concentration. As specific technologies mature into or beyond those stages, the private sector can then determine the pace for individual technologies to be scaled up for commercialization.

We have redirected the energy R&D budget in the Department based on this view of the Government's role. This chart shows by budget profile the entire Energy Department's R&D program from 1980 through fiscal 1983. You see that the basic science and applied research has stayed roughly level. Proof of concept has diminished slightly and major reductions have taken place in process development and commercialization.

In general, oil prices would have a much more direct impact on the introduction of new technology, the process development, and the commercialization side of the technology development scale, than they do on the basic and applied research side. We believe it is important, therefore, for the Government to maintain an essentially stable level of effort in these categories and to permit the private sector to choose and deploy technical options that may emerge from this work as the market forces dictate.

In other words, the Government can help insure that adequate energy is available at reasonable prices by continuing the fundamental generic research necessary to continue feeding new concepts into the industrial pipeline.

In maintaining this stable level of effort in the early stages of research, it is imporant that we maintain a diversity of technology efforts on the supply side as well as on the demand side.

Our third chart indicates the diversity of efforts that we have in our energy R&D program. This chart is the very last page of my formal testimony. This chart does not purport to be all the things we are working on, but it is the broader scope individual technologies within the areas of coal, synfuels, nuclear renewable, natural gas, petroleum on the supply side, as well as on the demand side; industrial, transportation, commercial, and residential.

While this chart does illustrate the diversity of the efforts we have in our energy R&D program, which of these technologies or how many of them eventually emerge as mainstays of our energy economy will depend very much on market factors, including projections of world energy prices. However, our role in the Government is to insure that the solid basis of information is put into place so that industry can choose from a wide slate of technologies and make decisions based on a sound technical and scientific understanding.

We believe this is the fundamental responsibility of Government for the future well being of our country. Thank you very much.

[The prepared statement of Mr. Mares follows:]

STATEMENT OF JAN MARES

Mr. Chairman and members of the committee:

Your letter of invitation states that the purpose of this hearing is to:

> examine various U.S. and global energy and economic projections, to investigate the validity of the various models used to arrive at these projections, and to explore their ramifications for U.S. energy R&D policy.

Also, discussions with committee staff indicated a specific interest in the results of the Department of Energy Electricity Policy Project and in a summary of the preliminary energy projections under development for the next National Energy Policy Plan.

This statement provides a discussion of three topics of concern to the committee:

- a discussion of the implications of lower oil price projections for Department of energy R&D and our views on the use of models in developing energy R&D policy;
- a summary of the preliminary National Energy Policy Plan projections along with a discussion of the model used to develop the projections (Appendix A); and
- a summary of the Electricity Policy Project (Appendix B).

Implications of Lower Oil Price Projections for Department of Energy R&D Activity

As discussed in Appendix A, world oil price projections have been revised downward repeatedly by Department of Energy and other analysts (including analysts within the private sector). The implications of this shift in perception upon the DOE planning process for energy R&D is but one of several factors that affect R&D planning. Chief among these other factors is the emphasis that the Administration has placed on basic and applied research as opposed to more commercial stages of R&D (e.g. demonstration). This is a change from the previous Administration and follows traditional views concerning the role of the federal government in R&D activity.

The distinction between the roles of the Federal government and the private sector is shown by the attached chart entitled "TECHNOLOGY DEVELOPMENT PATH" (Appendix C). This chart depicts the typical stages through which a new technology passes and relative amounts of expenditures at each stage as it matures from concept to commercial application. While we recognize that not all technologies fall precisely into these development steps, this chart enables policymakers to visualize the appropriate focus of the Federal government--namely, on the early stages of research and development.

Basic science is defined as the development of scientific knowledge, including a fundamental understanding of the physical and chemical properties of new or unconventional fuel sources or energy systems.

Applied research involves the broad engineering and physical science aspects of specific energy technologies. At this point, a better understanding of process, applications, or systems is gained, although practical utility may not yet be proven.

Proof-of-concept is where the technical viability of an energy concept is established. Enough is learned at this stage to establish the basic engineering feasibility of a concept and to forecast its expected economic and environmental performance standards. These are factors that permit industry to make subsequent decisions on whether the concept merits further development.

At the process development stage, increasingly large scale engineering design, construction and operation of energy systems takes place. The objective is to reduce technical risks and improve the process operability, reliability, economics and environmental impact.

Commercialization includes a wide variety of efforts to eliminate technical, economic, and institutional barriers to enable a new energy technology to gain acceptance in the marketplace.

The latter stages of this development path are the most costly, and this is where extensive private sector investments have occurred in the past and will continue to be directed in the future. For example, the gas industry, through its research arm, the Gas Research Institute, has projected annual R&D expenditures in the range of from $116 million in FY1983 to $168 million in 1988 (in constant 1984 dollars). While the gas industry invests some research funds in basic sciences (approximately $4.5 million in 1983) and in long-term supply options ($3.1 million in 1983), the bulk of its research funding is directed at more near-term supply options, more efficient utilization systems, and enhanced service in distribution and storage.

Likewise, the petroleum industry has underway approximately 220 enhanced oil recovery projects, essentially all of which are either commercial or field demonstration activities. The industry investment in these activities is estimated at approximately $200 million a year.

These are just two examples of the magnitude and emphasis of private sector funding. As part of its R&D planning activities, the Department is attempting to refine estimates of industry funding levels in each of the primary technology areas, including conservation and renewables. This task is complex due to the fact that such information is not routinely compiled today and in many cases, is considered highly proprietary by individual companies. However, it is well accepted within the research community that the focus of the majority of the private sector laboratories and research organizations is on R&D that has a near-term potential for returning significant payoffs to an individual firm. This R&D falls primarily within the "Process Development" and "Commercialization" categories of the chart in Appendix C.

On the other hand, projects in the earlier stages of the technology development path--in basic science and applied research--may have a very high benefit-to-cost ratio from a national perspective, but private sector investment is often limited or nonexistent. The ultimate benefits of these early stages of research may be quite large, yet they are frequently difficult to predict, highly risky, long-term, or cannot be captured by private firms.

The value of concentrating government research on these early stages of generic research as contrasted to the private sector's emphasis on the development of specific commercial products was described in an article entitled "Industrial Innovation Policy: Lessons from American History," which appeared in the February 18, 1983 issue of Science magazine.

The article points out that government R&D policies have historically been most successful where:

- o one, the government had a strong and direct procurement interest--in other words, it was the customer for the technology;

- o two, where some specific clienteles were involved--for example, the development of better seed varieties or improved methods of pest control for the agricultural industry. An important factor in the success of this type of government R&D, as the authors pointed out, was the existence of a Federal-State system of agricultural experimental stations. Yet, in other areas, where the government was seen more as a competitor, Federal efforts to spur R&D did not work;

- o three, where federal R&D has been in the "generic" area involving basic and applied research.

This latter area describes where the Federal energy R&D programs have been reoriented. The government is not the principal "customer" for new energy technologies; nor does the government have the resources or the expertise to determine if one specific energy "clientele" should be given preferential treatment over another. In both cases, it is the marketplace that ultimately must decide which technologies make the most commercial sense.

Yet, the early stages of research feed the private sector R&D investment pipeline. They are a necessary and important first step in establishing a viable slate of advanced energy options from which industry can choose.

Thus, there is a valid Federal role to provide front-end R&D support in a diversified spectrum of energy supply and demand technologies, and since FY1980, this is where the Federal government has shifted its energy R&D funding emphasis (as shown in Appendix C by the charts).

The distinction between basic and applied R&D and the introduction of new commercial technologies is extremely important. In general, oil prices would have a much more direct impact on the introduction of new technologies than it would on basic or applied R&D.

Basic and applied generic-type research has continued to be emphasized by the Department of Energy during this period of declining oil prices. To some extent it is probably true that cheaper oil supplies in the short-term allow us a longer period to investigate technological problems and implement technical development of oil substitutes. To the extent that our energy R&D knowledge base grows with time, this is a positive advantage of lower oil price projections and expectations. In addition, a lessening of a sense of economic urgency concerning the substitution of high cost imported oil should reduce the pressure for crash demonstration projects which would not have been wise to pursue.

Federal energy R&D policy results from the political process. Congress as well as the Administration and the private sector are active participants in determining the short and long-term direction and priorities for energy R&D. The underlying logic and substance of a particular R&D strategy is based on broad criteria that derive from national security goals, or environmental and energy goals, or relate to the nature of the technology itself - as in the case of magnetic fusion for example.

DOE energy market projections which affect R&D planning both within and outside the government are based on models--which are nothing more than a set of mathematical equations but are a good way of ordering a mass of information. As good as our models may be, there are limits on how well they can predict the future. The one constant in the future is change. No model we have can dispel this uncertainty, which is inherent in the future.

The practical question is how to deal with this uncertainty in making public policy. I want to emphasize that one of the reasons the Administration advocates a market approach to our energy and other economic problems is that the market encourages a diversity of private decisions. People are free to invest in the future as they see fit. If they are correct they can profit (and pay taxes). If they are wrong, they suffer losses.

With respect to R&D, we, of course, advocate a role for the Federal Government which focuses on basic research for the long-term. Our policy calls for stable funding levels adequate to support an appropriate level of effort on long-term issues. Funding levels would be determined by a variety of policy, programmatic and fiscal considerations, and would not be sensitive to changes in energy prices.

Energy Modeling and R&D Planning and Policy

A variety of modeling techniques are used to analyze energy R&D activity from specific engineering process phenomena to broad energy market trends. In general, detailed planning models are not relied upon for determining energy R&D priorities or policy. Instead more traditional reliance upon expert advice and direct kinds of studies are used to arrive at views concerning future R&D emphasis. The general context is the political process within which federal energy R&D policy is debated and formulated. Since the Administration emphasizes basic and applied research as opposed to commercialization-oriented R&D, Administration R&D planning is less affected by results of energy projections and modeling compared to the commercialization-oriented private sector.

The relationship between experts or modelers and policy decision makers is a key aspect of the usefulness of models for R&D policy and planning purposes. To the extent that a decision maker can shape the modeling exercise the more likely a model will be useful in the decision process. It is probably fair to say, however, that most modeling is performed as a separate and distinct analytical activity and, as a result, the process of modeling and decisionmaking is not a fully integrated process. In general, energy models are tools of energy experts and the advice of energy experts is just one element in a fairly complex decision process that leads to energy R&D policy.

Modeling is perhaps most sensitive in the area of forecasting and projections precisely because it can affect the expectations of policy makers. In this respect, we all have a lot to learn about the role of models or modeling results in formulating expectations - particularly energy market expectations. Certainly, there are both advantages and disadvantages or limitations to the use of models as tools for forecasting or policy analysis and planning. The following listing is offered as a selective rather than an exhaustive list.

MODELING ADVANTAGES

Implications of Assumptions: Models can show the implications of making a set of often complex, interrelated assumptions that would be difficult to untangle without use of a model.

Explicitedness: In general, models do generate fairly detailed quantitative results. Often the logical structure of the model is also quite apparent.

Problem Definition: Models tend to define problem areas with clarity and precision. The model becomes a way of perceiving a problem area. Differences among expert perception can be clearly discerned and understood.

Experimental Research Tool: Models can provide counter-intuitive results. As such they can be a legitimate scientific tool of inquiry.

Standardization and Speed of Results: Different groups can operate a single model and replicate results. Also assumptions can be varied individually to test impacts on model behavior while leaving all else unchanged. These model operations can often be performed quickly at relatively low cost.

MODELING LIMITATIONS OR DISADVANTAGES

Non-Accountability: Decision-makers are accountable for decisions not models or modelers. The difference in responsibility is crucial.

Non-Responsive: Models often can not take account of the most important concerns of policy-makers. Typically distributional, equity and fairness issues have to be dealt with through the political process.

Limiting Flexability: Models are representations of aspects of problems and cannot take account of the full-range of timely and relevant factors that influence the decision-making process.

Misunderstanding of Model Inputs: Often input data to a model are synthetic or imputed data rather than statistical observations. In addition a considerable amount of subjective judgments enter a model via the data used, the model structure, and exogenous assumptions made about "outside" factors that drive the model's results. These factors are often only superfically taken into account by model users and, as such, lead to considerable confusion regarding the validity of a model, its input data, the modeler involved, and the results of a model's use. These four aspects of policy modeling need to be very clearly kept in mind when evaluating or discussing a model or its results.

Inappropriate Use: Once a model is operational there is a tendency to use the model in all related analytical work, even though the model design is not appropriate for each application.

Inadequate Documentation: Models are often inadequately documented so that it is difficult for people to evaluate model structure.

Tendency to Rely on Old Data: Once a model is built there is a tendency to use the model without periodically reviewing structure and data to insure the most up-to-date assumptions These advantages and limitations are generic but can be directly applied to the areas of energy projection and energy R&D policy. The main message, perhaps, is that models are tools and as such can be appropriately and inappropriately used. A second implication is the often repeated notion that models and/or their results should not be a substitute for common sense. Policy makers are or should be accountable for their decisions and their questions and immediate concerns are generally dealt with through a variety of means - only one of which may be reliance upon expert opinion and the results of experts' models.

APPENDIX A
SUMMARY OF PRELIMINARY
NATIONAL ENERGY POLICY PLAN ENERGY PROJECTIONS

This appendix summarizes preliminary National Energy Policy Plan energy projections and caveats. These projections and caveats are under review within the Department of Energy and other government agencies and are subject to change. However, we believe these projections and caveats are close enough to final to provide the committee with a good indication of where the final results will come out. The final NEPP-83 energy projections will be available July 29, 1983. At that time a supplement to the National Energy Policy Plan entitled "Energy Projections to the Year 2010" will be distributed. The energy projections supplement will provide detailed tables of world and U.S. energy prices, demand and supply through 2010 and extensive discussion of the uncertainties of making and using such projections as well as the judgments of some economic forecasters about the projections.

Recognizing the inherent uncertainty associated with making long-term energy projections, the preliminary NEPP projections investigate a number of alternative scenarios which provide a range of results based upon different economic growth and energy market assumptions.

It is important to recognize that these projections are inherently uncertain. The uncertainty grows in the outyears. There are certainly many other valid views of how energy use and production may evolve. The Administration advocates reliance on market prices in part because the market encourages a variety of actions based on individual views of how markets may evolve.

Role of Energy Model Simulations In NEPP Projections

A Department of Energy computer simulation model called WOIL was used in developing the preliminary NEPP 83 energy projections. WOIL evolved from a model called COAL1 developed at Dartmouth College under a contract from the U.S. Department of the Interior. In 1977 COAL1 was improved under a contract from the Energy Research and Development Agency (ERDA) and was called FOSSIL1. FOSSIL1 included a variety of structural improvements which reflected comments from an in depth review of the COAL1 model performed by a consultant company. Despite the title, FOSSIL1 was a model of the entire U.S. energy system including demand and supply of all fuels, not just fossil fuels.

FOSSIL1 was revised to reflect assumptions and views of the U.S. Department of Energy and in 1978 a new model called FOSSIL2 was developed. After an interagency governmental review of the structure and results of FOSSIL2, the model was used as the basis for developing the NEP-II energy projections.

The world oil price was an exogenous input assumption to FOSSIL2. For NEPP-III, the Department of Energy developed an international structure to add to FOSSIL2. The new international model was called WOIL, a model which endogenously calculates world oil prices.

Both WOIL and FOSSIL2 have undergone considerable review both within and outside the Department of Energy. For example, both WOIL and FOSSIL2 have been extensively reviewed in Stanford Energy Modeling Forum exercises (Stanford University). In those studies the structure and results of WOIL and FOSSIL2 were compared with other energy models.

WOIL provides yearly calculations of world energy market conditions for the 1960 to 2010 timeframe. We test WOIL by evaluating the model's ability to reproduce historical trends from 1960 through 1982.

The following world regions are represented in WOIL:

- United States;
- Non-U.S. OECD (Organization for Economic Cooperation and Development) countries;
- Mexico;
- OPEC (Organization of Petroleum Exporting Countries);
- Rest of the Free World; and
- Centrally Planned Economies (CPEs--net energy trade only).

For each world region (except for the CPEs), WOIL projects primary energy supplied in terms of oil, gas, coal, nuclear and renewables (including production, net trade and stock changes). Energy consumption is projected by fuel (including electricity) and by sector (residential, commercial, industrial and transportation). Energy prices are calculated for both resource costs (e.g. minemouth coal) and delivered energy prices (including taxes, delivery charges and other markups).

To develop a scenario with WOIL requires many input assumptions. Critical assumptions include:

- Gross Domestic Product (GDP) by region;

- OPEC oil production capacity; and
- Net energy trade for oil, gas and coal from Centrally Planned Economies.

WOIL operates by iterating through the following sequence of calculations:

- the model starts with a specified set of initial conditions for energy prices, consumption and production for all fuels in all regions. For NEPP-IV the initial conditions were set for 1960;
- the model takes the input GDP assumption for each region and using a specified income elasticity (i.e. expected increase in total energy demand given an increase in economic activity) calculates a demand for energy;
- the demand for energy is modified through effects from delivered energy prices to estimate actual consumption of energy by sector and by fuel. The price effects include fuel switching because of relative price impacts and fuel conservation in response to price changes;
- a new set of energy prices is calculated for the next time period. Delivered energy prices are affected by the cost of energy (including capital costs), taxes and profits. For regulated fuels (e.g. electricity and historical natural gas prices), profits equal a specified "normal" rate of return. For other fuels, profits depend upon market conditions (including the price of fuels in international trade);
- the new energy prices affect the GDP input assumption for the next time period through a delivered price elasticity impact. Higher energy prices reduce economic activity and lower prices increase economic activity;
- the new achieved GDP is calculated which acts through an income effect to create a new set of energy demand conditions--thus completing the cycle;
- WOIL advances through time making the above sequence of calculations over and over.

Two positive features of using WOIL to develop long-term energy projections include:

- the model provides a consistent and complete accounting framework to insure that energy consumption balances energy supplies for all fuels in all Free-World regions for all years between 1960 and 2010. This accounting feature explicitly includes net energy trade among regions and energy transformation processes to produce electricity and synthetic fuels; and

- WOIL is relatively inexpensive and easy to operate. Consequently, WOIL can be used to explore the implications of alternative scenarios by varying assumptions. For example, WOIL can be operated under higher or lower economic growth assumptions to develop insight into the impacts of alternative economic conditions on energy prices, consumption and production.

Use of a mathematical model does not guarantee the quality of results. The quality of the results from complex models depends directly on the quality of the judgement used in making assumptions required to operate the model.

In using WOIL to develop the NEPP-IV energy projections, we have incorporated expert judgement in the choice of input assumptions to operate the model. Also, rather than relying on one midrange scenario, we have developed several scenarios with alternative assumptions and results. Finally, we have had a variety of energy experts review the NEPP-83 energy projections. A summary of critical comments from the experts will appear in the energy projections supplement to NEPP-83.

Range of Projections for World Oil Prices: A Retrospective View

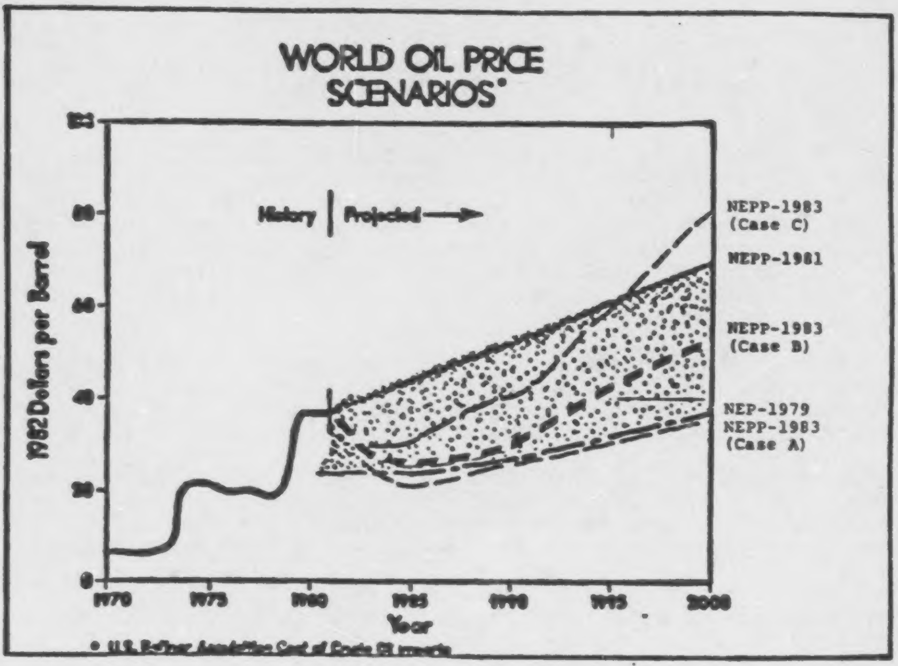
Nothing more clearly illustrates the difficulty in projecting future energy trends than does past NEPP world oil price projections. Figure 1 shows historical world oil prices (measured in 1982 dollars per barrel delivered to U.S. refiners) from 1960 through 1982, along with the following three separate projections of the world oil price:

- Projections prepared as part of the second National Energy Plan (NEP) submitted to Congress in May 1979.

- Projections prepared as part of the National Energy Policy Plan (NEPP) submitted to Congress in July 1981.

- Projections prepared in 1983 as part of the current National Energy Policy Plan (NEPP).

FIGURE 1



* U.S. Refiner Acquisition Cost of Crude Oil Imports

Each of the projections is representative of the views of many private and governmental analysts at the time of the projection. Each projection was regarded as reasonable, yet in less than 5 years (1979 to 1983), the projections have changed dramatically. For example, the 1985 world oil price measured in 1982 dollars has varied from a high of about $46.50 (NEPP-1981) to a low of about $25 (both NEP-1979 and NEPP-1983). New information and changes in the world situation are the primary reason for the variation in these recent world oil price projections.

NEP-79

The NEP-79 energy projections were developed at the time of the Iranian revolution, when U.S. net oil imports were close to 8 million barrels per day and OPEC production was over 30 million barrels per day. The assumption then was that any price increase due to the loss of Iranian production would be temporary; prices would have to return to "normal" when Iranian production came back into the market.

Long-term midrange assumptions were that world oil prices in the year 2000 would equal the cost of conventional crude oil substitutes such as shale oil, tar sands, and coal liquids. At the time that the NEP-79 world oil price projections were made, these unconventional sources of liquid fuels were estimated to cost between $35 to $50 per barrel in 1982 dollars.

Given the midrange NEP-79 price path, free world oil demand was projected to increase by 1.5 to 2 percent per year, reaching about 70 million barrels per day by the year 2000. Given this oil demand pattern, a major concern was the adequacy and security of oil supplies. OPEC oil production was projected to have to increase from about 30 million barrels per day in 1979 to equal 37 million barrels per day by 2000. The free world, as viewed in 1979, was facing increasing pressure on oil supplies with continuing and growing dependence on OPEC oil exports.

NEPP-81

The midrange NEPP-81 projections (the highest mid-price case shown in Figure 1) were based upon a decidedly different view of the world. By 1981, world oil prices had doubled in real terms and a war had broken out between Iran and Iraq, reducing OPEC production capacity by more than 6 million barrels per day. Toward the end of 1980, spot crude oil prices (prices for individual crude transactions) were in excess of $40 per barrel. It was inferred from these events that oil prices could conceivably remain high for many years.

In 1981, OPEC's long-term pricing strategy group announced that OPEC should link future oil price increases to the economic growth of the Organization for Economic Cooperation and Development (OECD) and the value of the dollar. Trends at that time indicated that implementation of the OPEC formula would result in a 2 to 3 percent per year real increase in oil prices over time. Further, Saudi Arabia announced a willingness to reduce its oil production to support a long-term pricing strategy.

Given the state of the world in 1980-81, it is not surprising that the midrange NEPP-81 world oil price projections, along with a variety of other projections made at that time, assumed a 2 to 3 percent per year real price increase into the future. Using a base 1980 price of about $39 (1982 dollars), this assumption resulted in a year 2000 world oil price for NEPP-81 of about $74 per barrel.

When used as a basis for projections and when coupled with the doubling of world oil prices in 1979-80, the NEPP-81 midrange price assumption caused free world oil demand to decline slowly over the 1980 to 2000 time period rather than increasing as in NEP-79. With lower oil demand, OPEC production in NEPP-81 was never projected to exceed 26 million barrels per day, implying considerable excess OPEC production capacity in the event of an oil supply disruption.

NEPP-83

Since 1980, world oil prices have declined steadily rather than climbing at a 2 to 3 percent per year real increase as assumed in NEPP-81. The main reason for the recent decline in oil prices has been unusually low demand for OPEC oil caused primarily by:

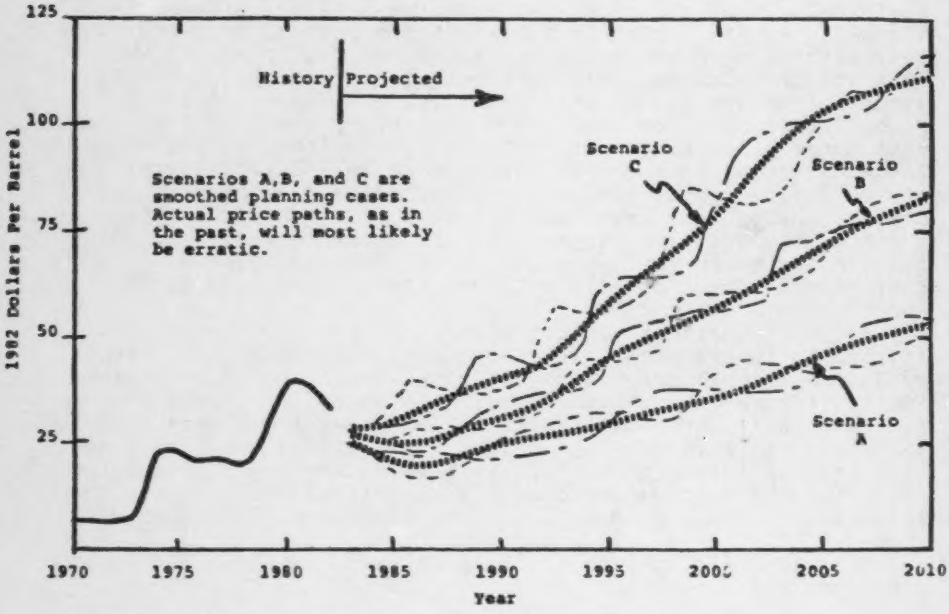
- Increased non-OPEC oil production and oil conservation and fuel switching in response to the oil price increases of 1973-74 and 1979-80
- Lower energy and oil demand due to the worldwide recession in 1981-82
- A worldwide drawdown of crude oil and petroleum product inventories

A key question now is: How are current market conditions and trends likely to evolve both in the near and longer term?

Though unexpected events and new information will undoubtedly alter the time path of future oil prices from our current projections, Figure 2 provides a summary of the range

FIGURE 2

PRELIMINARY NEPP-IV
WORLD OIL PRICE SCENARIOS*



Scenarios A,B, and C are smoothed planning cases. Actual price paths, as in the past, will most likely be erratic.

*U.S. Refiner Acquisition Cost of Crude Oil Imports of preliminary NEPP-83 price projections. As supported by the historical evidence of the 1970's, world oil prices are highly volatile. Yet, the price scenarios shown in Figure 2 are relatively smooth from 1985 to 2010. In fact, world oil prices are not likely to behave in such a smooth fashion. Oil supply disruptions, economic recessions and recoveries, unusually cold or warm weather, and other erratic events that directly affect world oil demand and supply will ensure that oil prices, as in the past, exhibit volatile behavior with periods of rapid price increase followed by periods of stable or declining prices. Each smooth price scenario in Figure 2, consequently, should be viewed as an average of many equally plausible but erratic price scenarios. The reason for presenting smooth paths which show underlying trends, is that such paths focus attention on longer term issues. The likely short-term volatibility of prices is important, however, because price fluctuations can prevent energy consumers and producers from knowing exactly which of the possible longer term price trends we are actually on. In any given year, the world oil price could be considerably above or below its underlying long-term trend.

Although there are potentially large inherent uncertainties related to future world oil prices--uncertainities that are reflected in the broad range of prices shown in Figure 2--some implications of these price ranges can be noted. World oil prices in all scenarios tend to fall in real terms from 1982 to the middle to late 1980's. Beyond 1990, prices are likely to rise in real terms, the major issue being whether prices (after averaging out fluctuations) will rise only slightly faster than inflation as Scenario A or much more rapidly as in Scenario C.

Some specific aspects of the price results shown in Figure 2 include the following:

- Unless the Iran-Iraq war suddenly ends or should world economic recovery not begin by 1984, world oil prices will most likely stabilize in the $23 to $30 per barrel range in 1983 and 1984 (1982 dollars).

- Between 1985 and 1990, demand for OPEC oil will steadily increase as world economic activity expands. Sometime between 1986 and 1990, demand for OPEC oil will reach 24 to 26 million barrels per day and significant upward price pressure will once again develop in the world oil market.

- By 1990, the world oil price in 1982 dollars will most likely be between $25 and $40 per barrel. Thus, the price in 1990 is expected to be about the same as the $34 per barrel price just prior to the sharp real price declines projected for the 1982 to 1985 period.

- Between 1990 and 2010, world oil prices are projected to increase in real terms reaching from $36 to $80 per barrel by the year 2000 and $55 to $110 per barrel by 2010. To repeat and emphasize, projections for the year 1990 and beyond are highly speculative.

- World oil prices are projected to rise between 1990 and 2010 in part because such a price rise, given our estimates of free world oil demand and non-OPEC oil supply, keeps demand for OPEC oil within what we consider to be a relatively stable range of 24 to 28 million barrels per day. Higher demand for OPEC oil, unless met with a significant increase in OPEC production capacity would eventually push world oil demand against an inelastic oil supply constraint, possibly causing world oil prices to increase more abruptly and to a higher level than might otherwise occur.

- A second reason for the 1990 to 2010 price increases is based on the assumption that the cost of such unconventional oil sources as shale oil and coal liquids will be in the $50 to $80 per barrel range (1982 dollars) as opposed, for example, to the $35 to $50 per barrel range assumed for NEP-79.

Conditions which would increase the likelihood of low price results include:

- A willingness of OPEC countries to expand both oil production and production capacity;

- A higher than expected potential for oil conservation and switching to alternative fuels like natural gas, coal, renewables, and electricity;

- No permanent major oil supply disruptions occur;

- The amount of remaining undiscovered oil and gas resources in non-OPEC countries turns out to be at the upper end of current estimates;

- Average world economic growth is low with a subsequent reduced demand for energy in general and oil in particular;

- The cost of alternatives to conventional oil, such as coal liquids, turns out to be at the lower end of current estimates and the production and use of such unconventional oil sources are not excessively restricted by water, environmental, capital, or other constraints; and

- No serious problems develop which inhibit the availability or use of non-oil fuels (for example, nuclear power moratoriums).

Conditions which would increase the likelihood of high oil price results are just the opposite of the above low price conditions.

The low price Scenario A in Figure 2 combines low oil price conditions, while the high oil price Scenario C combines high price conditions.

U.S. Energy Trends

This section highlights important preliminary U.S. energy trends from 1960 to 2010. The next section discusses alternative scenarios in which the two most uncertain conditions--world oil prices and economic growth--are allowed to vary from Case B assumptions.

Primary Energy Consumption

- From about 1950 to 1973, U.S. energy consumption grew at about the rate of economic growth, or 3.8 percent per year. In preliminary NEPP-83, energy consumption between 1982 and 2000 is projected to increase at only about 1.3 percent per year, less than half the 2.8 percent per year rate of U.S. economic growth.

- Starting in 1982, if U.S. energy consumption were to grow at the pre-1973 trend (that is, if energy consumption were to grow at the 2.8 percent per year rate projected for economic growth), U.S. energy consumption in the year 2000 would be more than 121 quadrillion Btu's (quads), which is about 30 percent more energy consumption than the 93 quads projected under midrange conditions. Consequently, improved energy efficiency in the economy is a very significant factor in determining long-term U.S. energy consumption patterns.

- From 1960 to 1977 there was a trend of steadily increasing reliance on oil imports that peaked at 24 percent of total U.S. energy consumption in 1977 (about 8.6 million barrels per day). Reaction to higher oil prices has reversed this trend. By the year 2000, U.S. net oil imports are projected to account for about 12 percent of total energy consumption (about 5 million barrels per day).

U.S. Energy Production

- U.S. oil and natural gas production peaked at a little over 40 quadrillion Btu's in the early 1970's (about half oil and half gas). We project that increased investment in oil and gas reserve development will maintain domestic oil and gas production at close to 37 to 40 quadrillion Btus per year through the 1980's. Beyond 1990, oil and gas are likely to become increasingly difficult to find and develop. Of course, unexpected breakthroughs in theories of where large undiscovered quantities of oil or gas might be found could alter the preliminary NEPP-83 production path.
- Coal, nuclear and renewable energy are all projected to increase substantially over the long term. In particular coal production is projected to increase in absolute terms more than that of any other fuel between 1980 and 2000. Part of coal's growth is the result of about a 4 percent per year projected growth in U.S. coal exports (from about 90 million tons in 1980 to about 200 million tons by the year 2000).

U.S. Primary Electricity Inputs

- Primary U.S. electricity inputs are projected to continue the historical trend of increasing as a percent of total primary energy consumption (from a 15 percent share in 1960 to a 31 percent share by 1980 and 42 percent of primary energy consumption by the year 2000).
- Coal's share of electricity generation is expected to increase from about 50 percent in 1980 to 59 percent by 2000. Oil and gas are projected to become priced out of most utility markets so that oil and gas generation drops from 27 percent in 1980 to about 8 percent by 2000.

Alternative Assumptions and Sensitivity Analysis

Most disparities among alternative energy projections result more from differences in key assumptions rather than from differences in analytical methods or sophistication of approach. For example, two important assumptions that affect projections of U.S. energy supply, demand, and prices are the rate of future U.S. economic growth and the future world oil price. To illustrate the importance of such assumptions, this section briefly summarizes some insights derived from an analysis of how changes in economic growth and world oil prices affect the future U.S. energy situation.

Impacts of High and Low Economic Growth

If all other assumptions are left at Case B values and we assume that U.S. economic growth is about 0.5 percent per year higher than the Case B assumption, the Case B modeling simulation results change as follows:

- With an increase in total economic activity, total energy consumption would increase. Also, given our assumption that electricity demand is strongly dependent on economic growth, electricity consumption would increase as well. For example, higher U.S. economic growth could increase total primary energy consumption in the year 2000 by about 12 percent (11.4 quads) and could increase electricity consumption by 10 percent (1.2 quads) over the Case B scenario.

- Higher economic growth, which increases demand for all fuels (including oil and gas), leads to a significant increase in oil and gas imports. Oil and gas demand increase while production remains relatively unchanged, thus increasing imports to satisfy domestic demand. By the year 2000, for example, net U.S. oil imports could equal about 6.0 million barrels per day, about 16 percent higher than the preliminary Case B amount of 5.2 million barrels per day.

- U.S. gas imports could rise significantly in the post-1990 time period, given higher economic growth. For example, under preliminary Case B assumptions, gas imports increase from about 1.9 trillion cubic feet in 1990 to 2.9 trillion cubic feet by 2010. With higher economic growth, gas imports could increase from about 2.2 trillion cubic feet in 1990 to equal as much as 3.5 trillion cubic feet by 2010.

- If U.S. economic growth were to be lower rather than higher than the Case B assumption, trends in energy consumption, oil and gas production, and oil and gas imports would be the opposite of the trends described above.

Impacts of Higher and Lower World Oil Prices

If all U.S. assumptions are left at Case B values and the world oil price is raised or lowered by 20 percent, the following modeling simulation results occur:

- Given a range in world oil prices of from $45 to $70 per barrel in the year 2000, net U.S. oil imports vary between a high of about 7 million barrels per day under low world oil prices to a low of about 3.7 million barrels per day under high oil prices.
- Higher oil prices stimulate U.S. liquids production, especially from such unconventional sources as enhanced oil recovery, tar sands, shale oil, and coal liquids. By the year 2000, for example, domestic liquids production (including coal liquids) could be about 10 percent higher under a $70-per-barrel world oil price compared to a $45-per-barrel world oil price.
- Although higher oil prices may increase the U.S. oil import bill and through other mechanisms have a negative effect on U.S. economic growth, higher oil prices do have one benefit: they stimulate world demand for coal. So, for example, under higher oil prices U.S. coal exports in the year 2000 are about 70 million tons per year higher than under lower oil prices.

Conclusions

This preliminary NEPP-83 projections analysis, along with a review of other recent private and government studies, provides some important general views about future energy trends.

- The oil price increases of 1973-74 and 1979-80 have set into motion powerful energy conservation forces that likely will continue to cause energy and especially oil to be used more efficiently in the world economy. Thus, to a large extent energy conservation has become as important as production in determining the future evolution of the U.S. and world energy situation. We, consequently, need to pay more attention to analyzing and evaluating energy conservation trends in world economies.
- The recent decline in world oil prices has added a new dimension to the uncertainty about future market conditions. During the past decade, OPEC never officially reduced the marker or posted price of oil,

but rather had used the influence of inflation to allow prices to fall gradually in real terms during periods of excess world supply. Now, investment planners must not only be concerned about the potential for oil price shocks, which can send the oil price very high, but investors must be concerned also about future price breaks which could send the price very low. Such concerns will undoubtedly lead to an additional risk premium to be associated with large-scale, long-term energy investments like new synthetic fuels plants.

- Over the long-term, stationary uses of oil and gas (primarily large and small boilers) will decline in importance as coal, renewables, electricity, and energy conservation increase in importance.

- Under all but extreme assumptions, both the United States and the rest of the world will remain dependent on oil supplies from the countries of OPEC throughout the next 20 years. Given the unstable situation in the Middle East and elsewhere, the oil consuming nations should continue efforts to prepare for and try to prevent or reduce the effects of future oil supply disruptions.

- Finally, much uncertainty underlies these projections. Several analysts believe the lowest price case (Scenario A) is most likely. Others believe higher prices will occur (Scenario B or C). For planning purposes, no single price path is sufficient to account for various unforeseen events and/or future market conditions.

APPENDIX B

SUMMARY OF THE ELECTRICITY POLICY PROJECT AND ITS IMPLICATIONS FOR R&D STRATEGY

For the past eighteen months, the electricity group in the Policy office has concentrated on an intensive review of issues pertaining to the achievement of long-term economic efficiency in the electric power industry. This effort, known as the Electricity Policy Project, has led to the publication of more than 30 technical reports on electricity-related subjects, and an integrative analysis titled The Future of Electric Power in America. The latter document was recently published. Several copies have already been sent to the Committee, and the Department will be happy to provide more if they are needed.

Given the Project's focus on long-term economic efficiency, the analysis is concentrated chiefly on economic, financial and institutional issues, as opposed to engineering or technological questions. Nevertheless, the analysis comes to some conclusions which have significant implications for R&D strategy. The study's principal conclusions are summarized briefly below.

Electricity Demand Growth

- Over the past decade, conservation has sharply reduced the trend in electricity demand growth. If pre-1973 demand growth patterns had continued, our requirements for generating capability would be 120 gigawatts greater today.
- However, electricity demand has still continued to grow faster than GNP. (Peak electricity demand, which grew 1.8 times as fast as GNP from 1960 to 1973, grew 1.4 times as fast as GNP from 1973 to 1982. For average electricity demand, the comparable ratios are 1.7 and 1.2).
- Future electricity demand is expected to grow approximately in proportion to GNP. The report assumes a median national average growth rate of 3%/year with "high" and "low" projections of 4%/year and 2%/year. This range is consistent with most current forecasts, although substantial regional variation is likely.
- The prices for almost all forms of energy have risen substantially in the past decade. These upward price trends will probably continue, although at different

rates for different energy forms. These price increases have been and will continue to be major driving forces behind increased efficiency in energy use and reductions in energy demand growth.

- However, the price of electricity has risen less steeply than the prices of oil and gas. Moreover, through 2000 we expect the price of electricity to become still more competitive with other energy forms.
- Largely as a result of these shifting price relationships, electricity consumption as a share of total delivered energy has risen from 6.2% in 1960 to 14.3% in 1982. Our projections show it rising to about 18% in 2000.

Electricity Supply Projections

- Current electricity supplies are well in excess of what is needed to maintain reliable service. The national average reserve margin in 1982 was 40%. However, it is the 1990 supply picture that is relevant to today's supply decisions, given the long lead times of new generation.
- At 3% yearly demand growth, current supplies plus 100 gigawatts of capacity under construction will maintain the adequacy of supply through the early 1990s. Given lead times, decisions on new generation could be close at hand once demand growth picks up with economic recovery. (Again, substantial regional variation is expected.)
- Despite reduced oil prices (both current and projected), construction of new coal or nuclear plants to displace existing oil- or gas-fired baseload units continues to be in the consumer's best interest.
- Although decentralized power sources are likely to experience substantial growth in their markets, the bulk of new supplies in this century will still come from traditional central-station technologies.
- At 3 % yearly load growth, as much as a trillion dollars (1982$) of new plant investment will be required by the year 2000 to meet demand and replace physically and economically obsolete plant.

Finance

- The financial condition of the electric power industry has improved over the past 18 months. However, the industry is still much weaker than it was ten years ago.
- Aggregate industry financial statistics are less significant than the financial incentives for the industry to undertake necessary investment in the future. These incentives turned negative ten years ago and despite some variance from state to state, remain generally negative today.
- In order to assure sufficient electricity supplies at minimum cost in the long term, it will be important to create proper incentives for the industry to pursue least-cost futures.

Implications of these Findings

Consider first the implications of these findings in general terms, and then the implications for R&D strategy. First, it is likely that our electric utility network is going to become still more important as a component of our economic infrastructure. Second, it is likely that some large investments (that is, large in amount though not as a fraction of GNP) will be required to maintain electric utilities which are economically efficient.

If these investments are not made, the results would probably not be blackouts, brownouts, scheduled load-shedding, etc. More likely but less visible results would be increased reliance by utilities on purchased power, reversion of economically obsolete units to baseload usage, and the hasty addition of oil- or gas-fired combustion turbines (which have high operating costs) for baseload usage. All of these options will tend to raise electric rates, and correspondingly adversely effect economic growth.

The third and most disturbing implication is that the incentives for this industry currently work against making the capital investment that will be necessary to ensure adequate electricity supplies at minimum cost. For some years now, the industry has been losing money on new investments, even though those investments were generally in the ratepayers' long-term interest. In these circumstances, the industry has a strong disincentive toward investment, and the financial community has already indicated its lack of enthusiasm for such investments. On the plus side, in the past year, the rate of inflation has abated considerably, and some PUC's have shown keen insight into the significance of the incentives issue.

Where, then, do we go from here? For our part, we are looking for broad public scrutiny of our findings and input from all interested parties on what Federal role, if any, is appropriate to assure an adequate and efficient electric power system in the long term. We recognize that there is a diversity of views and circumstances within the industry as well as among state and local jurisdictions which have regulatory authority over the electric utility industry. For that reason, the conclusions in this report are intended to provide a springboard for discussion and debate on the critical issues affecting electricity in this country.

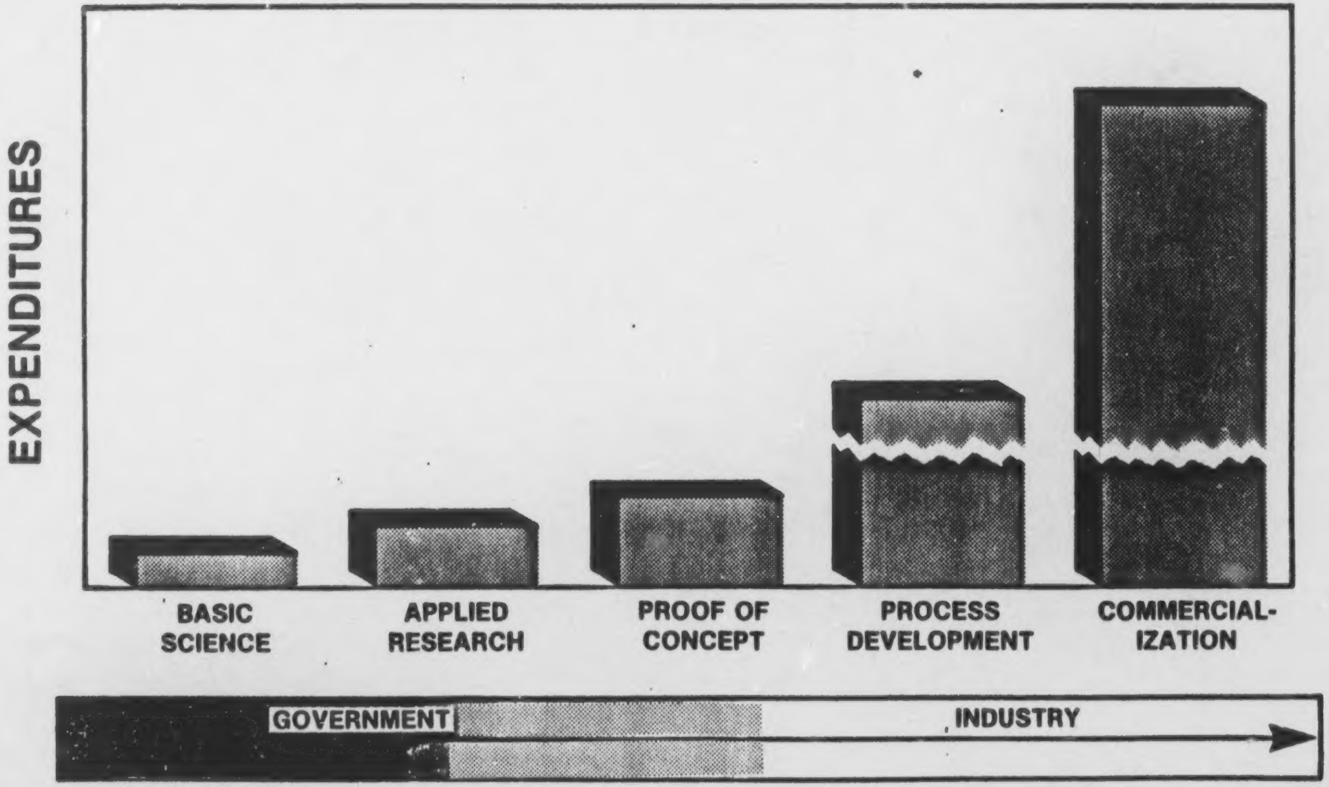
In particular, we are not seeking to preempt the states. We are not seeking to create an intrusive Federal presence. We are not predisposed to the conclusion that Federal action is necessary. Our strategy is to present our views on the long-term prospects for electric power and to leave open the issue of possible initiatives at the Federal or state level.

This study did not address issues of R&D strategy for utilities. Also, we have not yet evaluated the implications of the study for DOE planning. Consequently, we cannot at this time offer specific insights for R&D planning from the study. Some general insights, however, do seem relevant. It is appropriate to continue to dedicate the sums proposed by the President in the Budget to electricity-related problems and technologies. Electricity is going to be more important than ever to our economic and social well-being. We need to continue to address some of the unresolved issues associated with both traditional central-station generation technologies and decentralized generation (e.g. wood, wind, photovoltaic, and solar thermal) and the environmental aspects of coal use, nuclear waste disposal and nuclear safety.

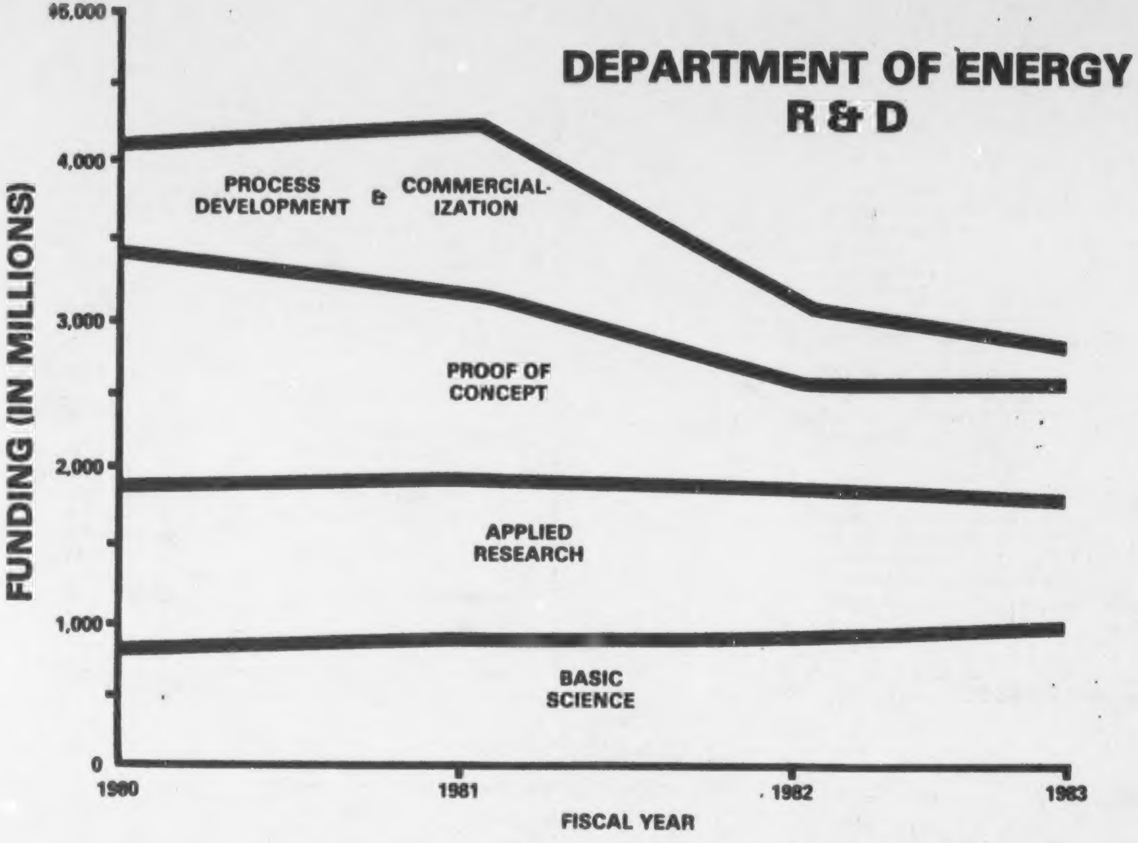
APPENDIX C

CHARTS FOR TESTIMONY

TECHNOLOGY DEVELOPMENT PATH



DEPARTMENT OF ENERGY
R & D



*Preliminary Estimates

DOE ENERGY R&D
— SLATE OF TECHNOLOGIES —

SUPPLY TECHNOLOGIES

COAL

- COAL CLEANING
- ADVANCED CONTROL SYSTEMS
- NEW COMBUSTION METHODS
- COAL-SLURRY FUELS
- FUEL CELLS
- MHD

SYNFUELS

- COAL GASIFICATION
- COAL LIQUEFACTION
- OIL SHALE
- TAR SANDS

PETROLEUM

- ENHANCED OIL RECOVERY

NATURAL GAS

- TIGHT SANDS
- DEVONIAN SHALES
- GEOPRESSURED
- METHANE HYDRATES
- DEEP SOURCE GAS

RENEWABLES

- SOLAR
- WIND
- BIOMASS
- GEOTHERMAL
- OCEAN THERMAL
- HYDRO

NUCLEAR

- BREEDER REACTORS
- CONVERTER REACTORS
- ADVANCED NUCLEAR SYSTEMS

DEMAND TECHNOLOGIES

INDUSTRIAL

- IMPROVED COMBUSTION EFFICIENCY
- WASTE HEAT RECUPERATORS
- INDUSTRIAL HEAT PUMPS
- WASTE CONVERSION
- SEPARATION SYSTEMS

TRANSPORTATION

- HEAT ENGINES
- ELECTRIC VEHICLES
- ALTERNATIVE FUELS UTILIZATION
- ADVANCED MATERIALS

COMMERCIAL/RESIDENTIAL

- INSULATION
- HEAT PUMPS
- LIGHTING
- FURNACES
- HIGHER EFFICIENCY BUILDING ENVELOPES

JUNE [illegible]

Mr. **Fuqua**. Thank you, Jan.
Dr. Rivlin.

STATEMENT OF DR. ALICE M. RIVLIN, DIRECTOR, CONGRESSIONAL BUDGET OFFICE

Dr. **Rivlin**. Mr. Chairman, I, too, am pleased to appear before this subcommittee to discuss the Government's energy research-and-development policy. As you pointed out in your statement, many elements of today's energy research-and-development policy were shaped by prospective assessments of oil markets that no longer prevail. Thus, a reexamination of Federal support for energy R&D is appropriate.

In my testimony today, I will focus on three questions: What is the long-term prospect for oil prices? What potential problems does this assessment of the oil market pose? What are the resulting implications for energy R&D policy?

Oil prices lie at the heart of energy policy because of their influence on energy prices in general and in particular, on the rate at which oil is displaced as the world's primary energy source. In the Congressional Budget Office's view, oil prices are likely to remain roughly constant—in real terms—through the rest of this decade at least.

Assuming that the economic recovery now taking shape is maintained—even at slower growth rates than those indicated by past business cycles—and that the Organization of Petroleum Exporting Countries retains its basic unity, the prospect that real oil prices will continue to drift downward appears to us to be slight. What seems more likely is a continuation of the pattern in which oil prices rise in ratchets and subsequently diminish in real terms, and occasionally in nominal terms. Such a price path will not eliminate the United States need for an inevitable transition from oil, but it may postpone that need.

On the demand side of the oil market, the two principal uncertainties are the growth of the world economy and the pace of increased displacement by means of conservation and substitution—both factors crucial in the recent decline in oil demand. Between 1979 and 1983, oil consumption in the free world has dropped significantly—from about 51 million barrels per day to about 45 million barrels. At least half of this decline can be ascribed to increased conservation worldwide.

The rest is probably attributable to slow economic growth; this part of the reduction may be reversed as world economic growth resumes. Sustained recovery worldwide would lead to the greater energy demands associated with higher income levels and increased industrial output—especially in nations developing an industrial base.

Continued energy conservation and substitution of other fuels for oil will offset some of the higher energy demands associated with greater economic activity. These forces were set in motion by the wave of oil price increases that followed the Iranian revolution in 1979. Within the United States, for example, oil prices rose from about $12.50 per barrel in 1978 to about $30 today, and oil imports have, in turn, dropped from more than 8 million barrels per day to about half that amount.

Yet, though conservation has played a major role in trimming oil demand, the U.S. economy's energy efficiency may not continue to improve at the rate of the past several years. Further improvement can be foreseen in some cases, such as the automotive and aviation fleets, in which older, less energy-efficient vehicles will be retired. But many of the last few years' conservation gains involved one-time only shifts in energy use—such as turning down thermostats—and may be hard to repeat.

With oil prices at their current levels, other conservation and substitution activities may not be economic. For example, substituting coal for oil in electric utility boilers generally appears economic when the price of oil reaches $35 per barrel. With oil prices at $30 per barrel, many such conversions are not cost effective. Conservation and substitution with nonpetroleum fuels may also have been slowed by lower expectations of future oil prices. Certainly, the potential for greater energy efficiency and substitution of other fuels for oil is still great. But the CBO does not expect these gains to outweigh the increases in oil demand anticipated to come with economic growth and higher income levels.

With these factors in mind, the CBO foresees free world oil demand of about 52 million barrels a day in 1990. This is considerably lower than the demand levels the CBO envisioned before the oil market's reaction to the price increases set off by the Iranian revolution.

The smaller demand raises two major uncertainties on the supply side of the oil market. The first of these concerns OPEC unity. The cartel has thus far withstood severely depressed oil markets and bitter conflicts among its members. If oil prices are to be maintained, OPEC's cooperation will have to continue. If indeed free world oil demand reaches 52 million barrels per day by 1990, then the daily demand for OPEC oil will probably be about 25 million barrels.

Though this is lower than most estimates of OPEC's capacity, it is probably enough to allow OPEC to continue to allocate it among its members. Thus, the CBO expects OPEC to remain a powerful force in the oil market. A related uncertainty concerns non-OPEC sources of oil—notably Mexico and China, the two non-OPEC producers with the greatest apparent resource potential for growth. Since both nations are constrained by problems related to politics and scarce capital and foreign exchange, these difficulties may cause non-OPEC oil supplies to be smaller than their resource potential suggests.

Even more than other areas of forecasting, long-term judgments regarding oil prices are necessarily somewhat speculative. When the various uncertainties within and around the oil market are balanced, though, they do suggest a pattern of constant real prices into the 1990's. Though this is a more moderate price path than the one envisioned in the late 1970's, when much of current energy policy was made, it does not mean that the longrun energy problem is solved. Ultimately, the United States still faces an inevitable transition away from oil, since world reserves are finite. But a more moderate price path may afford extra time to make the transition.

Although the need to replace oil as the United States primary energy source is clearly the central longrun U.S. energy problem, policy also must address possible short-term interruptions in the supply of imported oil. Indeed, while lower expected oil prices defer the United States need to make a speedy transition away from petroleum use, they may, by simultaneously encouraging petroleum consumption and discouraging domestic production, increase our short-term vulnerability to supply disruptions.

Policy tools other than research and development, however, seem most appropriate to confronting the possibility of short-term supply interruptions. Rapid filling of the strategic petroleum reserve, particularly during the current soft oil market, offers good insurance against the economic effects of supply disruptions. In addition, if the concentration of U.S. oil imports from Persian Gulf suppliers is the cause of U.S. vulnerability, then a policy of diversifying sources of supply might offer additional protection.

Any policy that encourages conservation of oil contributes both to the longer run transition away from oil use and to reduced dependence on oil imports in the event of a disruption. An oil import fee would encourage both conservation and additional domestic oil exploration. Other policy options are available to correct market imperfections that impede an orderly transition to other energy forms. A good example is appliance and automobile labeling to guide purchasing decisions toward energy-efficient products.

Energy research and development should be seen as one of a variety of policies available to promote a transition away from imported oil and ultimately, toward renewable energy sources. Energy R&D activities can be seen as a means to accelerate the development of specific energy technologies or as a way to diversify the base from which market forces will select technologies for commercialization.

During most of the 1970's, the Department of Energy's R&D programs promoted specific energy technologies for commercialization in pursuit of energy independence for the United States. Toward the end of the decade, DOE had become the third largest Federal source of R&D funding, with budget authority for R&D amounting to $4.8 billion in fiscal year 1980. Of that sum, $3.7 billion went for civilian applications. Government funding was provided to projects with adequate market incentives, on grounds that there was an overriding national interest in accelerating the rapid replacement of oil in the economy.

As a result, the R&D programs initiated by the DOE in the late 1970's were heavily oriented toward development instead of basic and applied research. Of the total 1980 DOE budget for civilian R&D, 70 percent was devoted to development, a commitment that involved the Government in questions of technological choice. Funding went for an array of energy development ranging in sophistication from nuclear to passive solar technologies.

By 1983, DOE's R&D budget had fallen slightly, to $4.6 billion in current dollars. Within that total, the allocation of spending has shifted. Two factors have been the strongest determinants of a recent redirection of the total Federal R&D budget—increased defense spending and reduced public intervention in the private market.

Defense-related spending by DOE in the 1984 budget request is 68 percent greater than the 1980 level—a real increase of 32 percent—so that the defense-related share of DOE R&D spending has grown from less than one-quarter to more than two-fifths of the total. In terms of energy R&D per se, funding for basic research in advanced physics and energy-related sciences has doubled in current dollar terms. Funding for development, on the other hand, has been reduced from more than $2.5 billion in 1980 to less than $1 billion in 1984. That is more graphically shown on Mr. Mares' charts.

On the basis of the administration's forecasts of inflation rates, this represents a real decline of more than 70 percent. Development accounts for only 35 percent of the DOE civilian R&D budget proposed by the administration for 1984.

Nuclear energy R&D has been least affected by these cuts. In current dollars, total nuclear R&D—for both fission and fusion power—is higher in the 1984 proposal and is $1.29 billion, including $270 million requested for R&D related to the construction and operation of the Clinch River Breeder Reactor. In general, though, nuclear R&D spending has been slightly reoriented, away from development and toward research.

Corrected for inflation, nuclear development funding proposed for 1984 is significantly higher than for 1983, but it is well below the 1980 level. But compared to development expenditures for other energy forms, nuclear development spending has increased. In the proposed budget for 1984, nondefense nuclear development expenditures account for 91 percent of total energy development expenditures, in contrast to 41 percent in 1980.

It should also be noted that about 10 percent of the roughly $1.3 billion spent for nuclear R&D goes to the uranium enrichment and radioactive waste disposal programs, for which user fees are collected to defray costs.

The bulk of the reductions in DOE R&D have fallen on nonnuclear energy technologies—conservation, fossil fuels, solar energy, and geothermal energy—with most cuts coming from development. The budget request for development spending in these technologies is only 5 percent of the 1980 level. The proposed fiscal year 1984 DOE budget also calls for a slight real dollar increase in the research funding for these areas. Thus, the recent pattern of DOE R&D funding has eliminated development funding for non-nuclear civilian energy technologies in order to boost funding for defense activities and basic research, leaving nuclear funding more or less unchanged.

These spending patterns raise several issues for congressional consideration. First, a large body of evidence suggests that the Government's record of successfully bringing technologies to commercial use is not good. This implies that, as a general rule, funding for development projects should be limited, leaving commercialization to the private sector and concentrating Government efforts on research.

If recent trends in energy markets suggest that the need to displace petroleum is less urgent than previously thought, then the Federal commitment to the development of specific technologies could be reevaluated. Research in alternative technologies is a suitable response to the long-term problem of displacing oil use, but other policy tools—for example, tax incentives or pricing initiatives—might be more effective in inducing the commercialization of new energy technologies.

In aggregate terms, the DOE R&D budget has already made significant steps toward this reorientation away from commercialization and toward research. Yet, the Government is still funding very expensive development projects, such as the breeder reactor and synfuels. Loan and price guarantees authorized by the Synfuels Corporation, for instance, dwarf most of the on-budget allocations for energy R&D; the total funding that will be available to the Synfuels Corporation for such guarantees is $17.4 billion.

To limit further Government involvement in commerce, two conditions might be applied: first, that there is a strong private interest, backed by financial commitments; and second, that the private enterprise would encounter significant barriers—for example, a likelihood that the technology would be copied by competitors. Even under these conditions, however, other policies, such as antitrust approval for joint research, might be more appropriate than direct Federal funding.

Another point concerns the distribution funding of among different fields of energy research. If Federal energy R&D policy goal is to provide a diverse technological base from which market forces can select projects for commercialization, then the existing program may be too narrowly focused on nuclear power and synthetic fuels development. The shift from development to research has been applied far more extensively to conservation, to renewable energy sources, and to conventional fossil fuels than to these types of energy.

This pattern risks undermining the market-based selection of alternatives to imported oil by subsidizing some technologies and not others. The payoff to private investments in conservation, for instance, appears to have been higher than to investments in nuclear power; yet, this is not reflected in the proposed DOE budget. For 1984, Government spending for conservation is cut by 82 percent from the 1980 level, while nuclear R&D is funded at a higher level.

Further, the energy R&D program cannot be completely understood by looking only at DOE research. R&D with a bearing on energy policy is also conducted in other areas—such as metallurgy, environmental science, and mining technology—and with the support of other Federal departments and agencies—for instance, the Department of Defense, the National Science Foundation, and the Synfuels Corporation. The CBO is now preparing a report assessing the Federal R&D effort and presenting a unified Federal research and development budget.

Finally, it should be noted that the bulk of the Nation's R&D effort—both within the energy field and in other areas—occurs in the private sector. Thus, stimulating private research initiatives is an important avenue of energy R&D policy. The Economic Recovery Tax Act of 1981 provided new tax incentives for private R&D, and tax credits now exist for innovations that conserve energy or substitute renewable energy forms in industry.

Consideration might be given to allowing greater cooperation among firms and industries in R&D activities that could lead to improved energy efficiency—for example, allowing or encouraging greater industrywide cooperation to improve automotive fuel economy. The Federal Government might relax antitrust restrictions or it could provide seed money for such cooperative efforts and insure that federally funded applied research programs are better structured to support private sector efforts. Yet, private R&D efforts in the energy area are probably best encouraged by an energy policy that allows for the correct pricing of fuels and brings realistic market signals to energy users and producers.

Thank you, Mr. Chairman.

[The statement of Dr. Rivlin follows:]

STATEMENT OF DR. ALICE M. RIVLIN, DIRECTOR, CONGRESSIONAL BUDGET OFFICE

Mr. Chairman, I am pleased to appear before this Subcommittee to discuss the federal government's energy research and development (R&D) policy. Many elements of today's energy R&D policy were shaped by prospective assessments of oil markets that no longer prevail. Thus, a reexamination of federal support for energy R&D is appropriate.

In my testimony today, I will focus on three questions:

What is the long-term prospect for oil prices?

What potential problems this assessment of the oil market pose?

What are the resulting implications for energy R&D policy?

Oil prices lie at the heart of energy policy because of their influence on energy prices in general and in particular, on the rate at which oil is displaced as the world's primary energy source. In the Congressional Budget Office's view, oil prices are likely to remain roughly constant (in real terms) through the rest of this decade at least. Assuming that the economic recovery now taking shape is maintained—even at slower growth rates than those indicated by past business cycles—and that the Organization of Petroleum Exporting Countries retains its basic unity, the prospect that real oil prices will continue to drift downward appears to us to be slight. What seems likelier is a continuation of the pattern in which oil prices rise in ratchets and subsequently diminish in real terms, and occasionally in nominal terms. Such a price path will not eliminate the United States; need for an inevitable transition from oil, but it may postpone that need.

On the demand side of the oil market, the two principal uncertainties are the growth of the world economy and the pace of increased displacement by means of conservation and substitution—both factors crucial in the recent decline in oil demand. Between 1979 and 1983, oil consumption in the free world has dropped significantly—from about 51 million barrels per day to about 45 million barrels. At least half of this decline can be ascribed to increased conservation worldwide. The rest is probably attributable to slow economic growth; this part of the reduction may be reversed as world economic growth resumes. Sustained recovery worldwide would lead to the greater energy demands associated with higher income levels and increased industrial output—especially in nations developing an industrial base.

Continued energy conservation and substitution of other fuels for oil will offset some of the higher energy demands associated with greater economic activity. These forces were set in motion by the wave of oil price increases that followed the Iranian revolution in 1979. Within the United States, for example, oil prices rose from about $12.50 per barrel in 1978 to about $30 today, and oil imports have, in turn, dropped from more than 8 million barrels per day to about half that amount. Yet, though conservation has played a major role in trimming oil demand, the U.S. economy's energy efficiency may not continue to imporve at the rate of the past several years. Further improvement can be foreseen in some case, such as the automotive and aviation fleets, in which older, less energy-efficient vehicles will be retired. But many of the last few years' conservation gains involved one-time-only shifts in energy use—such as turning down thermostats—and may be hard to repeat. With oil prices at their current levels, other conservation and substitution activities may not be economic. For example, substituting coal for oil in electric utility boilers generally appears economic when the price of oil reaches $35 per barrel. With oil prices at $30 per barrel, many such conversions are not cost-effective. Conservation and substitution with nonpetroleum fuels may also have been slowed by lower expectation of future oil prices. Certainly, the potential for greater energy efficiency and substitution of other fuels for oil is still great. But the CBO does not expect these gains to outweigh the increases in oil demand anticipated to come with economic growth and higher income levels.

With these factors in mind, the CBO foresees free world oil demand of about 52 million barrels per day in 1990. This is considerably lower than the demand levels the CBO envisioned before the oil market's reaction to the price increases set off by the Iranian revolution.

This smaller demand raises two major uncertainties on the supply side of the oil market. The first of these concerns OPEC unity. The cartel has thus far withstood severely depressed oil markets and bitter conflicts among its members. If oil prices are to be maintained, OPEC's cooperation will have to continue. If indeed free world oil demand reaches 52 million barrels per day by 1990, then the daily demand for OPEC oil will probably be about 25 million barrels. Though this is lower than most estimates of OPEC's capacity, it is proably enough to allow OPEC to continue to allocate it among its members. Thus, the CBO expects OPEC to remain a powerful force in the oil market. A related uncertainty concerns non-OPEC sources of oil—notably Mexico and China, the two non-OPEC producers with the greatest apparent resource potential for growth. Since both nations are constrained by problems related to politics and scarce capital and foreign exchange, these difficulties may cause non-OPEC oil supplies to be smaller than their resource potential suggests.

Even more than other areas of forcasting, long-term judgments regarding oil prices are necessarily somewhat speculative. When the various uncertainties within and around the oil maket are balanced though, they do suggest a pattern of constant real prices into the 1990s. Though this is a more moderate price path than the one envisioned in the late 1970s, when much of current energy policy was made, it does not mean that the longterm energy problem is solved. Ultimately, the United States still faces an inevitable transition away from oil, since world reserves are finite. But a more moderate price path may afford extra time to make the transition.

Although the need to replace oil as the United States' primary energy source is clearly the central long-run U.S. energy problem, policy also must address possible short-term interruptions in the supply of imported oil. Indeed, while lower expected oil prices defer the United States' need to make a speedy transition away from petroleum use, they may, by simulataneously encouraging petroleum consumption and discouraging domestic production, increase our short-term vulnerability to supply disruptions.

Policy tools other than research and development, however, seem most appropirate to confronting the possibility of short-term supply interruptions. Rapid filling of the Strategic Petroleum Reserve, particularly during the current soft oil market, offers good insurance against the economic effects of supply disruptions. In addition, if the concentration of U.S. oil imports from Persian Gulf suppliers is the cause of U.S. vulnerability, then a policy of diversifying sources of supply might offer additional protection.

Any policy that encourages conservation of oil contributes both to the longer-run transition away from oil use and to reduced dependence on oil imports in the event of disruption. An oil import fee would encourage both conservation and additional domestic oil exploration. Other policy options are available to correct market imperfections that impede an orderly transition to other energy forms. A good example is applicance and automobile labeling to guide purchasing decisions toward energy-efficient products.

Energy research and development should be seen as one of a variety of policies available to promote a transition away from imported oil and ultimately, toward renewable energy sources. Energy R&D activities can be seen as a means to accelerate the development of specific energy technologies or as a way to diversify the base form which market forces will select technologies for commercialization.

During most of the 1970s, the Department of Energy's R&D programs promoted specific energy technologies for commercialization in pusuit of energy independence for the United States. Toward the end of the decade, DOE had become the third larges federal source of R&D funding, with budget authority for R&D amounting to $4.8 billion in fiscal year 1980. Of that sum, $3.7 billion went for civilian applications. Government funding was provided to projects with adequate market incentives, on grounds that there was an overriding national interest in accelerating the rapid replacement of oil in the economy. As a result, the R&D programs initiated by the DOE in the later 1970s were heavily oriented toward development instead of basic and applied research. Of the total 1980 DOE budget for civilian R&D, 70 percent was devoted to development, a commitment that involved the government in questions of technological choice. Funding went for an array of energy development ranging in sophistication from nuclear to passive solar technologies.

By 1983, DOE's R&D budget had fallen slightly, to $4.6 billion in current dollars. Within that total, the allocation of spending has shifted. Two factors have been the strongest determinants of a recent redirection of the total federal R&D budget—increased defense spending and reduced public intervention in the private market. Defense-related spending by DOE in the 1984 budget request is 68 percent greater than the 1980 level (a real increase of 32 percent), so that the defense-related share of

DOE R&D spending has grown from less than one quarter to more than two-fifths of the total. In terms of energy R&D per se, funding for basic research in advanced physics and energy-related sciences has doubled in current-dollar terms. Funding for development, on the other hand, has been reduced from more than $2.5 billion in 1980 to less than $1 billion in 1984. On the basis of the Administration's forecasts of inflation rates, this represents a real decline of more than 70 percent. Development accounts for only 35 percent of the DOE civilian R&D budget proposed by the Administration for 1984.

Nuclear energy R&D has been least affected by these cuts. In current dollars, total nuclear R&D (for both fission and fusion power) is higher in the 1984 proposal is $1.29 billion including $270 million requested for R&D related to the construction and operation of the Clinch River Breeder Reactor. In general, though, nuclear R&D spending has been slightly reoriented, away from development and toward research. Corrected for inflation, nuclear development funding proposed for 1984 is significantly higher for 1983, but it is well below the 1980 level. But compared to development expenditures for other energy forms, nuclear development spending has increased. In the proposed budget for 1984, nondefense nuclear development expenditures account for 91 percent of total energy development expenditures, in contrast to 41 percent in 1980. It should also be noted that about 10 percent of the roughly $1.3 billion spent for nuclear R&D goes to the uranium enrichment and radioactive waste disposal programs, for which user fees are collected to defray costs.

The bulk of the reductions in DOE R&D funding have fallen on non-nuclear energy technologies—conservation, fossil fuels, solar energy, and geothermal energy—with most cuts coming from development. The budget request for development spending in these technologies is only 5 percent of the 1980 level. The proposed fiscal year 1984 DOE budget also calls for a slight real-dollar decline in the research funding for these areas. Thus, the recent pattern of DOE R&D funding has eliminated development funding for non-nuclear civilian energy technologies in order to boost funding for defense activities and basic research, leaving nuclear funding more or less unchanged.

These spending patterns raise several issues for Congressional consideration. First, a large body of evidence suggests that the government's record of successfully bringing technologies to commercial use is not good. This implies that, as a general rule, funding for development projects should be limited, leaving commercialization to the private sector and concentrating government efforts on research. If recent trends in energy markets suggest that the need to displace petroleum is less urgent than previously thought, then the federal commitment to the development of specific technologies could be reevaluated. Research in alternative technologies is a suitable response to the long-term problem of displacing oil use, but other policy tools—for example, tax incentives or pricing initiatives—might be more effective in inducing the commercialization of new energy technologies.

In aggregate terms, the DOE R&D budget has already made significant steps toward this reorientation away from commercialization and toward research. Yet the government is still funding very expensive development projects, such as the breeder reactor and synfuels. Loan and price guarantees authorized by the Synfuels Corporation, for instance, dwarf most of the on-budget allocations for energy R&D; the total funding that will be available to the Synfuels Corporation for such guarantees is $17.4 billion. To limit further government involvement in commercialization, two conditions might be applied: first, that there is a strong private interest, backed by financial commitments; and second, that the private enterprise would encounter significant barriers—for example, a likelihood that the technology would be copied by competitors. Even under these conditions, however, other policies, such as antitrust approval for joint research, might be more appropriate than direct federal funding.

Another point concerns the distribution funding of among different fields of energy research. If federal energy R&D policy goal is to provide a diverse technological base from which market forces can select projects for commercialization, then the existing program may be too narrowly focused on nuclear power and synthetic fuels development. The shift from development to research has been applied far more extensively to conservation, to renewable energy sources, and to conventional fossil fuels than to these types of energy. This pattern risks undermining the market-based selection of alternatives to imported oil by subsidizing some technologies and not others. The payoff to private investments in conservation, for instance, appears to have been higher than to investments in nuclear power; yet this is not reflected in the proposed DOE budget. For 1984, government spending for conservation is cut by 82 percent from the 1980 level, while nuclear R&D is funded at a higher level.

Further, the energy R&D program cannot be completely understood by looking only at DOE research. R&D with a bearing on energy policy is also conducted in other areas—such as metallurgy, environmental science, and mining technology—and with the support of other federal departments and agencies (for instance, the Department of Defense, the National Science Foundation, and the Synfuels Corporation). The CBO is now preparing a report assessing the federal R&D effort and presenting a unified federal research and development budget.

Finally, it should be noted that the bulk of the nation's R&D effort—both within the energy field and in other areas—occurs in the private sector. Thus, stimulating private research initiatives is an important avenue of energy R&D policy. The Economic Recovery Tax Act of 1981 provided new tax incentives for private R&D, and tax credits now exist for innovations that conserve energy or substitute renewable energy forms in industry. Consideration might be given to allowing greater cooperation among firms and industries in R&D activities that could lead to improved energy efficiency—for example, allowing or encouraging greater industry-wide cooperation to improve automotive fuel economy. The federal government might relax antitrust restrictions or it could provide seed money for such cooperative efforts and ensure that federally funded applied research programs are better structured to support private-sector efforts. Yet private R&D efforts in the energy area are probably best encouraged by an energy policy that allows for the correct pricing of fuels and brings realistic market signals to energy users and producers.

Mr. FUQUA. Thank you very much, Dr. Rivlin.

Dr. Willis.

STATEMENT OF DR. ERIC H. WILLIS, DIRECTOR OF RESEARCH, INTERNATIONAL ENERGY AGENCY, OECD

Dr. WILLIS. Thank you, Mr. Chairman. I am also very glad to be here.

By way of introduction, my name is Eric Eillis and I am presently Director of Research for the International Energy Agency in Paris. I am on leave from the Office of Technology Assessment of this Congress and was formerly Deputy Assistant Secretary of Energy Technologies at the inception of DOE.

The focus of attention this morning is quite properly on the effect of the lowering of oil prices on energy research and development investment. It is a subject we have been much concerned with in the IEA. That there have been very profound changes in attitude toward energy R&D there can be little doubt. The causes, however, are complex, and the lowering of the oil price is but one of many of a number of interlocking factors. There are pitfalls in pulling these factors apart, and one can easily be led to hasty conclusions.

There is a curious psychological factor in the lowered oil price—even at $29 per barrel, it stands at a level we would have thought catastrophic when this committee first embarked on major energy R&D programs in the mid-seventies. This is a fact we ought to keep in mind as we discuss this subject. I would like to discuss for a moment the factors influencing the rate of development of energy technologies over the course of the past 4 years.

One must remember that the slackening in the oil price is a response to a slackening of demand. In turn, the slackening of demand resulted from a combination of conservation measures taking hold, recessive forces causing slackening energy demand—idle factories don't use energy—a warmer than normal northern hemisphere winter, and some extensive stock draw down on the part of oil companies. Of the four, conservation measures had been brought about by a combination of Government actions; for example, fleet averages for automobiles, and price signals magnified by the oil price shock of 1979-80.

There were some forceful price signals fortified by the perception that $34 would not be the end of the matter and that increased prices could safely be bet upon for the future. Such betting indeed was done—the drive for synfuels alone was fueled by the feeling that even if the product was not competitive today, it would be tomorrow. In that year, however, the world saw only the first storm clouds of a recession, and energy R&D planning in IEA countries mostly envisaged massive Government intervention and, one might add, not whole, discouraged, industry. In that year also, as a result of first the Tokyo and then the Venice summit, the IEA undertook a study, chaired by the then-United States Under Secretary for Energy, to drive even harder for the commerialization of alternative energy sources. The report of this group, good though it was at the time, now takes on all the charisma of an obituary column, listing one dinosaur after another. It is instructive and rather chastening to reflect on how considered judgments look foolish in a short period of time.

It is also instructive, however, to note that the reversal of the trend toward instant commercialization took place prior to the slackening of the oil price. The principal ingredients in the demise of major projects were cost overruns beyond any inflationary indices, high interest rates which made times to pay back too long to contemplate, and a product price which made even the most optimistic enthusiast hesitate to endorse. The lowering of the oil price put nails in the coffin—it did not itself kill it. The new administration of 1981, for reasons based on the basic philsophic premise that Government had no business in commercialization anyway, withdrew support for such ventures. Their decision to withdraw from the SRC-II project was unpopular at the time with their international partners, who, despite their initial shocked reaction, may nevertheless have later had cause to be less irate as the blight of recession bit into the Western economies and budgets.

Instead of cutting Government budgets by ideological choice, as in the United States, other western governments were forced to cut back of necessity as growing unemployment simultaneously cut revenues and added to the welfare rolls. Recession, therefore, was having a much more pronounced effect in 1981 and 1982 than was the slackening of the oil market and the lowering of the price. It still has the predominant effect today, in 1983, but the oil price gives the added impetus and rationale to back off from energy R&D funding. Generally, IEA governments are resisting this temptation and a longer range view appears to be prevailing.

In assessing national response to energy R&D, one should remember that this implies the combined efforts of both Government and industry. The contribution of industry should be evaluated much more carefully than it has been. Unfortunately, it has not been possible, despite careful research at the IEA and by other member governments, to assess industry's contribution with much accuracy—it is inherently very difficult. Thus the contention in some quarters that industry is providing the front running in many energy R&D areas is, in most instances, unsubstantiated by hard data.

It is particularly regrettable but understandable that no data of a level which bears much analysis is available in DOE. It is precisely in the industrial sector that a combination of high interest rates and oil price perceptions are likely to have a dampening effect on energy R&D investment and there should be some mechanism for evaluating the effects. Our experience at the IEA is that this data is absolutely essential if the total course of energy R&D investment is to be monitored in those areas where industry's concerns are the most immediate.

To get a grip on this question, the IEA has recently undertaken an energy security study, endorsed by the IEA Governing Board at the ministerial level in May of this year. These forecasts are remarkably similar to others we have heard this morning. In fact, one gets a little alarmed by the remarkable similarities. I would like to think it is because we are uncommonly wise, but it may be that we are looking over each others' shoulders too much.

The energy outlook for the rest of the century will fall into three periods. In the next 5 years, there will be a continuance of the present easy market conditions with substantial surplus capacity until the mid-1980's or a little later.

Around 1990, a gradual tightening of the energy and oil markets, leading to a situation around 1990 in which demand for oil from the OPEC countries is at a level which would put upward pressure on prices and make the OECD area vulnerable to a new oil price shock, which could be caused by even a small interruption in supply.

I think one has to remember how little the shortfall actually was that caused the 1980 shock.

From the early 1990's to 2000, increasingly tight energy and oil markets in the 1990's; effective policy measures in the meantime to improve energy efficiency and increase energy supply could ease this situation, but there is a clear possibility of substantially higher energy prices leading to a new check to economic growth.

According to this forecast, then, the present climate of oil price will prevail for the rest of this decade. This should provide us with a stable period to plan. How then should we approach our task, acknowledging as we do so that the world is a different place now than in the seventies, and is not likely to revert to the conditions of that time?

There is a temptation to lump R&D investment in energy technologies together into one large bag. Energy technologies are not a homogenous entity. They have different applications, different levels of scientific sophistication, different time horizons, and face different impediments to progress. Funding levels are disparate; some involve large installations while others involve a multitude of small investments.

If then, one wishes to examine the effect of outside factors on energy technologies, it may be useful to consider them as belonging to six groups, each of which has common policy decision characteristics. These are:

First, technologies designed to maximize the role of alternative conventional fuels to oil, especially coal and nuclear, in near to mid-term;

Second, technologies which make the use of energy more efficient;

Third, technologies which promise large contributions in the future, but are high risk, and whose introduction would coincide with depletion of fossil resources;

Fourth, the technology base which forms the springboard from which technological options may be created;

Fifth, technologies which exploit renewable energy sources;

Sixth, cross-cutting technologies, which include the efficient production and transmission of energy and technologies related to safety and public health.

Perhaps we should take a look at these six categories.

Coal and nuclear, with gas, offer major diversification away from oil. This is important not only to keep the demand for oil down, but to insure that the overdependence on one fuel does not lead to a vulnerability to our economies. This could lead to serious hardship as oil markets eventually tighten.

Coal and nuclear both suffer from serious barriers to their market penetration. While solutions to removing such barriers are by no means all technical, many are. Coal requires clean use for societal acceptability, while reactor safety and waste management continue to haunt nuclear power. The U.S. Federal Energy R&D budget spends 20 percent of its total on conventional nuclear, including safety and waste issues, but less funding goes into insuring that coal finds its entree into wider use. Rather, the mechanism for increasing coal's acceptability is principally the environmental regulatory process coupled with coal's price advantage over oil.

Costs are borne by industry. The lowering of the price of oil, therefore, cuts into coal's competitive edge, and the cost of coal cleanup technologies takes up a larger percentage of the reduced margin. I think this is a situation which should be closely watched.

Conservation is perhaps the most vulnerable energy area to oil price change. After the initial surge of conservation measures, for which we seem to be congratulating ourselves, investment in the second round of energy efficiency is bound to prove more expensive. The first round was heavily geared to cutting out waste, so costs were not so heavy and rewards large and immediate. Perhaps our self-congratulations in fact have a hollow ring. Under these circumstances, industry is going to be very hard-nosed in adopting the fruits of Government RD&D or embarking on their own.

Continued high interest rates, a certain acclimation to higher prices, and less return on investment in terms of money saved, are going to take their toll—from now on, it will cost more money to save money. When one considers that conservation is partially responsible for the reduction in energy demand, any retrogression at this time will only serve to increase demand and result in a tightening of the oil market. Thus, the conservation momentum will have to be maintained, and a healthy RD&D effort geared both to increased energy efficiency and to reduce the cost of the conservation methods needed to achieve that efficiency.

The future scenario I have given allows no complacency for the future, even as it allows a respite for the present. Fossil fuels will inevitably decline, although their time frame for doing so is more extended than we may have imagined in the early seventies. Thus, it behoves us to invest in options for the future, but perhaps with less sense of stampede and more deliberation. I believe we must have available technological options in the synthetic fuels area in the future even though the present outlook seems bleak—there is plenty to do short of commercialization.

The breeder technology also should not be driven by current oil price—it is future resource driven; for example, the availability of natural uranium at the right price. Currently this technology makes little economic sense, but we cannot have long-term options foreclosed by every short-term whim. In this vein, fusion energy represents the exploitation of the only energy source in prospect for tomorrow—ultimately we have to have it, the only questions being when, and at what funding levels in the meantime. None of these long-range activities should be at all influenced by the short-term oil market.

The technology base is one of the secret weapons of the American economy—it is the seed corn of the harvest of the future, and to be neglected at our peril. We certainly cannot afford to withhold our investment in it on the rather spurious contention that other countries will only exploit it first. The secret is in the rapid exploitation of that base. I see no sign at all of a decline in the funding of basic energy sciences as I look around the major IEA countries—quite the contrary. This area should be relatively free of oil market considerations and should be geared instead to understanding phenomena which underpin tomorrow's innovations.

The progress of renewable energy is a much less clear-cut issue, since there are a number of forces at work simultaneously. One of our objectives, I well remember, before this very committee, when serious funding started at the beginning of ERDA, was to help create a viable industry. To a large degree, this has happened, and one can point to photovoltaics, wind energy, alcohol fuels, and solar heating as instances where what was intended to happen did in fact happen. Thus, RD&D investment, in some of these areas anyway, can be expected to diminish as other new opportunities appear and make their claims on funding. Change, then, is both inevitable and desirable.

More than oil price, the perception that oil will be available much longer may now be having an effect on renewable energy investment. The climate of urgency which surrounded the late seventies has dissipated—there is a remarkable dearth of articles extolling their virtues and urging immediate action. This is not an unalloyed disaster—it gives us time to pursue new ideas without demanding their instant appearance in the marketplace, and allows existing ideas the time to achieve reduced first cost and greater reliability.

The pricing of competitive fuels, particularly electricity, and tax structures, either to equalize their marketplace position or give a temporary advantage, continue to have a very significant impact on renewable energies and their R&D support.

It would appear, therefore, that oil price per se is but one of a number of factors influencing renewable energy. First, cost and reliability coupled with high interest rates are perhaps the dominant considerations at the present time.

Finally, the health and safety of their citizens is a prime responsibility of governments, and is conducted largely independent of the price of any particular fuel. Research ito this area appears well supported among IEA countries. Cross-cutting transportation technologies, such as electrical transmission and coal slurry pipelines, are marketplace dependent, and competitive economics call the tune—oil price is certainly part of the refrain.

In conclusion, an overall RD&D investment strategy, which every government should consider, will have to take into account the timeframe for technological development, the most probable scenarios for the energy supply/demand balance, the various stimuli and inhibitors, and the potential contribution of an energy a source. What we now have available to us is a period of relative stability in which, while the immediate heat is off, the future demands our most deliberate efforts pursued with determination and imagination. The oil price of today is an irrelevancy of tomorrow. The strictures of Omar Khayam are still quite appropriate: "The moving finger writes, and having writ, writes on, nor all thy piety nor wit, can bring it back to cancel half a line nor all thy tears erase one word of it."

It is the preparation in calmer times which allows flexibility for the future.

Thank you, sir.

[The prepared statement of Dr. Willis follows:]

TESTIMONY OF DR. ERIC H. WILLIS, DIRECTOR OF RESEARCH AT THE INTERNATIONAL ENERGY AGENCY, OECD, PARIS, FRANCE

By way of introduction, my name is Eric Willis and I am presently Director of Research at the International Energy Agency in Paris. I am on leave from the Office of Technology Assessment of this Congress and was formerly Deputy Assistant Secretary of Energy Technologies at the inception of DOE.

The focus of attention this morning is quite properly on the effect of the lowering of the oil price on energy R&D investment. It is a subject we have been much concerned with in the IEA. That there have been very profound changes in attitude towards energy R&D there can be little doubt. The causes, however, are complex, and the lowering of the oil price is but one of many of a number of interlocking factors. There are pitfalls in pulling these factors apart, and one can easily be led to hasty conclusions. There is a curious psychological factor in the lowered oil price—even at $29 per barrel it stands at a level we would have thought catastrophic when this Committee first embarked on major energy RD&D programs in the mid-1970's. This is a fact we ought to keep in mind as we discuss this subject. I would like to discuss for a moment the factors influencing the rate of development of energy technologies over the course of the past four years.

One must remember that the slackening in the oil price is a response to a slackening of demand. In turn, the slackening of demand resulted from a combination of conservation measures taking hold, recessive forces causing slackening energy demand (idle factories dont use energy), a warmer than normal northern hemisphere winter, and some extensive stock draw down on the part of oil companies. Of the four, conservation measures had been brought about by a combination of government actions (e.g., fleet averages for automobiles) and price signals magnified by the oil price shock of 1979/80, when the price reached $34 per barrel. There were some forceful price signals fortified by the perception that $34 would not be the end of the matter and that increased prices could safely be bet upon for the future. Such betting indeed was done—the drive for synfuels alone was fueled by the feeling that even if the product was not competitive today, it would be tomorrow. In that year however, the world saw only the first storm clouds of a recession, and energy R&D planning in IEA countries mostly envisaged massive government intervention and, one might add, not wholly discouraged by industry. In that year also, as a result of first the Tokyo and then the Venice Summit, the IEA undertook a study, chaired by the then US Under-Secretary for Energy, to drive even harder for the commercialization of Alternative Energy Sources. The report of this group, good though it was at the time, now takes on all the charisma of an obituary column, listing one dinosaur after another. It is instructive however to note that the reversal of the trend towards instant commercialization took place prior to the slackening of the oil price. The principal ingredients in their demise were cost overruns beyond any inflationary indices, high interest rates which made times to pay back too long to contemplate, and a product price which made even the most optimistic enthusiast hesitate to endorse. The lowering of the oil price put nails in the coffin—it did not itself kill it. The new Administration of 1981, for reasons based on the basic philosophic premise that government had no business in commercialization anyway, withdrew support for such ventures. Their decision to withdraw from the SRC-II project was unpopular with their Japanese and German partners who, despite their initial shocked reaction, may have later had cause to be less irate as the blight of recession bit into the Western economies and budgets. Instead of cutting government budgets by ideological choice, as in the US, other western governments were forced to cut back of necessity as growing unemployment simultaneously cut revenues and added to the welfare rolls. Recession, therefore, was having a much more pronounced effect in 1981 and 1982 than was the slackening of the oil market and the lowering of the price. It still has the predominant effect today, in 1983, but the oil price gives the added impetus and rationale to back off from energy RD&D funding. Generally, IEA Governments are resisting this temptation and a longer range view appears to be prevailing.

In assessiong national response to energy RD&D, one should remember that this implies the combined efforts of both government and industry. The contribution of industry should be evaluated much more carefully than it has been. Unfortunately it has not been possible, despite careful research at the IEA and by some Member governments, to assess industry's contribution with much accuracy—it is inherently very difficult. Thus the contention in some quarters that industry is providing the front running in many energy R&D areas is, in most instances, unsubstantiated by hard data. It is particularly regrettable but understandable that no data of a level which bears much analysis is available in DOE. It is precisely in the industrial sector that a combination of high interest rates and oil price perceptions are likely to have a dampening effect on energy RD&D investment and there should be some mechanism for evaluating the effects. Our experience at the IEA is that this data is absolutely essential if the total course of energy RD&D investment is to be monitored in those areas where industry's concerns are the most immediate.

A future assessment

To get a grip on this question, the IEA has recently undertaken an energy security study, endorsed by the IEA Governing Board at Ministerial level in May this year.

A continuance of the present easy market conditions with substantial surplus capacity until the mid-1980s or a little later.

Around 1990: A gradual tightening of the energy and oil markets, leading to a situation around 1990 in which demand for oil from the OPEC countries is at a level which would put upward pressure on prices and make the OECD area vulnerable to a new oil price shock, which could be caused by even a small interruption in supply.

From Early 1990's to 2000: Increasingly tight energy and oil markets in the 1990s; effective policy measures in the meantime to improve energy efficiency and increase energy supply could ease this situation, but there is a clear possibility of substantially higher energy prices leading to a new check to economic growth.

According to this forecast, then, the present climate of oil price will prevail for the rest of this decade. This should provide us with a stable period to plan. How then should we approach our task, acknowledging as we do so that the world is a different place now than the seventies, and is not likely to revert to the conditions of that time?

Policy considerations for the future

There is a temptation to lump R&D investment in energy technologies together into one large bag. Energy technologies are not a homogenous entity. They have different applications, different levels of scientific sophistication, different time horizons, and face different impediments to progress. Funding levels are disparate; some involve large installations while others involve a multitude of small investments.

If then, one wishes to examine the effect of outside factors on energy technologies, it may be useful to consider them as belonging to six groups, each of which has common policy decision characteristics. These are:

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Second, technologies which make the use of energy more efficient.

Third, technologies which promise large contributions in the future, but are high risk, and whose introduction would coincide with depletion of fossil resources.

Fourth, the technology base which forms the springboard from which technological options may be created.

Fifth, technologies which exploit renewable energy sources.

And finally, cross-cutting technologies, which include the efficient production and transmission of energy and technologies related to safety and public health.

Perhaps we should take a look at these six categories.

Coal and Nuclear, with gas, offer major diversification away from oil. This is important not only to keep the demand for oil down, but to ensure that the over-dependence on one fuel does not lead to a vulnerability to our economies. This could lead to serious hardship as oil markets eventually tighten.

Coal and Nuclear both suffer from serious barriers to their market penetration. While solutions to removing such barriers are by no means all technical, many are. Coal requires clean use for societal acceptability, while reactor safety and waste management continue to haunt nuclear power. The US Federal Energy RD&D Budget spends nearly 37 percent of its total on conventional nuclear, including safety and waste issues, but little concommittant funding goes into ensuring that coal finds its entree into wider use. Rather, the mechanism for increasing coal's acceptability is principally the environmental regulatory process coupled with coal's price advantage over oil. Costs are borne by industry. The lowering of the price of oil, therefore, cuts into coal's competitive edge, and the cost of coal clean-up technologies takes up a larger percentage of the reduced margin. I think this is a situation which should be closely watched.

Conservation is perhaps the most vulnerable energy area to oil price change, if this is downwards. After the initial surge of conservation measures, for which we are congratulating ourselves, investment in the second round of energy efficiency is bound to prove more expensive. The first round was heavily geared to cutting out waste, so costs were not so heavy and rewards large and immediate. Perhaps our self congratulations have a hollow ring. Under these circumstances industry is going to be very hard nosed in adopting the fruits of government RD&D or embarking on their own. Continued high interest rates, a certain acclimatisation to higher prices, and less return on investment in terms of money saved, are going to take their toll—from now on it will cost more money to save money. When one considers that conservation is partially responsible for the reduction in energy demand, any retrogression at this time will only serve to increase demand and result in a tightening of the oil market. Thus the conservation momentum will have to be maintained, and a healthy RD&D effort geared both to increased energy efficiency and to reduce the cost of the conservation methods needed to achieve that efficiency.

The future scenario I have given allows no complacency for the future, even as it allows a respite for the present. Fossil fuels will inevitably decline, although their time frame for doing so is more extended than we may have imagined in the early 70's. Thus it behoves us to invest in options for the future, but perhaps with less sense of stampede and more deliberation. I believe we must have available technological options in the synthetic fuels area, in the future, even though the present outlook seems bleak—there is plenty to do short of commercialisation. The breeder technology also should not be driven by current oil price—it is future resource driven, i.e., the availability of natural uranium at the right price. Currently this technology makes little economic sense, but we cannot have long term options foreclosed by every short term whim. In this vein fusion energy represents the exploitation of the only energy source in prospect for tomorrow—ultimately we have to have it, the only questions being when, and at what funding levels in the meantime. None of these long range activities should be at all influenced by the short term oil market.

The technology base is one of the secret weapons of the American economy—it is the seed corn of the harvest of the future, and to be neglected at our peril. We certainly cannot afford to withhold our investment in it on the rather spurious contention that other countries will only exploit it first. The secret is in the rapid exploitation of that base. I see no sign at all of a decline in the funding of basic energy sciences as I look around the major IEA countries—quite the contrary. This area should be relatively free of oil market considerations and should be geared instead to understanding phenomena which underpin tomorrow's innovations.

The progress of Renewable Energy is a much less clear cut issue, since there are a number of forces at work simultaneously. One of our objectives, I well remember, when serious funding started at the beginning of ERDA, was to help create a viable industry. To a large degree this has happened, and one can point to photovolatics, wind energy, alcohol fuels, and solar heating as instances where what was intended to happen did in fact happen. Thus R&D investment, in some of these areas anyway, can be expected to diminish as other new opportunities appear and make their claims on funding. Change, then, is both inevitable and desirable.

More than oil price, the perception that oil will be available much longer may now be having an effect on renewable energy investment. The climate of urgency which surrounded the late seventies has dissipated—there is a remarkable dearth of articles extolling their virtues and urging immediate action. This is not an unalloyed disaster—it gives us time to pursue new ideas without demanding their instant appearance in the market place, and allows existing ideas the time to achieve reduced first costs and greater reliability.

The pricing of competitive fuels, particularly electricity, and tax structures, either to equalize their market place position or give a temporary advantage, continue to have a very significant impact on renewable energies and their R&D support.

It would appear therefore that oil price per se is but one of a number of factors influencing Renewable Energy. First cost and reliability coupled with high interest rates are perhaps the dominant considerations at the present time.

Finally, the health and safety of their citizens is a prime responsibility of governments, and is conducted largely independent of the price of any particular fuel. Research into this area appears well supported among IEA countries. Cross cutting transportation technologies, such as electrical transmission and coal slurry pipelines, are market place dependent, and competitive economics call the tune—oil price is certainly part of the refrain.

In conclusion, an overall RD&D investment strategy, which every government should consider, will have to take into account the timeframe for technological development, the most probable scenarios for the energy supply/demand balance, the various stimuli and inhibitors, and the potential contribution of an energy a source. What we now have available to us is a period of relative stability in which, while the immediate heat is off, the future demands our most deliberate efforts pursued with determination and imagination. The oil price of today is an irrelevancy of tomorrow. The strictures of Omar Khayam are still quite appropriate:

The moving finger writes,
And having writ, writes on
Nor all thy piety nor wit
Can bring it back to cancel half a line
Nor all thy tears erase one word of it."

It is the preparation in calmer times which allows flexibility for the future

Mr. FUQUA. Thank you very much, Dr. Willis.

Let me thank all of our panel for a very well-thought out and excellent presentation. I did find one, I think, glaring omission in all of the statements. While we work on economic models and so forth and we talk about supply and demand and where we are going in the future. we have omitted political instability that we can't predict. That seems to be one of the major factors determining whether or not we should proceed with R&D activities and develop alternative sources. Because regardless if the models that have been presented are accurate, and I have no reason to question that, we still leave this very important item of political instability in parts of the world that can lead us back where we were in 1973.

To me, I know you can't factor that into an economic model sometimes but it is a very important criterion that I think we should not omit or in any way lessen the importance of it.

We thought we had plenty of energy sources prior to 1973 and President Nixon proclaimed that we would have energy independence in 10 years, which we have not. But we have made great strides and I think all of this testimony was very excellent.

Dr. Rivlin, you mentioned that the Congressional Budget Office is preparing a report on the Federal R&D budget. Could you kind of describe this a little more in depth and when it might be available?

Dr. RIVLIN. The report will be available in a few months, Mr. Chairman, and it is an attempt, not the first, but we hope a useful one to look across the whole spectrum of Federal agencies and try to pull into one place and describe and categorize consistently the R&D efforts of the Federal Government.

Mr. FUQUA. I think several touched upon it and maybe all of you might want to comment, but how reliable are the models we use now for predicting long-term energy oil price movement?

Dr. RIVLIN. Do you want me to start?

Mr. FUQUA. OK.

Dr. RIVLIN. Not very. As recent history proves. I think one might expect that the models are now more reliable than they were a few years ago. Just because we have had recent history when we looked ahead in the seventies at what might happen to energy demand and supply in the face of large price changes, with almost nothing to go on, we never had large price changes and a model is, after all, only a systemization of what you have learned from the past and there wasn't much past experience to go on.

Now, there is a lot more and the models can pick up how the world economy does respond both on the supply side and on the demand side to major changes in price. That should make them better. It is never, as you pointed out yourself, Mr. Chairman, going to be possible to put into a model unexpected political events or anything like that. So at best what you have is a systemization of the past experience and that is useful, but it shouldn't be relied on as certain and truth.

Mr. FUQUA. Mr. Evered, would you like to comment?

Mr. EVERED. Mr. Chairman, I can't possibly improve on what Dr. Rivlin has just said. I agree with it.

Mr. FUQUA. Mr. Evered, on page 7 of your statement on you list the total energy and oil consumption forecast for 1990 from 1977 through 1982. Between the 1979 and 1982 reports, we see that the 1990 total energy consumption forecast declined by about 8.9 percent, from 90 quads to 82 quads.

On the other hand, the projected 1990 oil consumption forecast rose by nearly 8.8 percent from 16 to 17.4 million barrels per day. What accounts for this increasing role of oil in the 1990 forecasts?

Mr. EVERED. Mr. Chairman, as you will observe from the table, virtually all the increase in projected oil consumption occurred between 1981 and 1982 in our outlook for 1990, that is virtually entirely a function of the prospect for switching in the utility and industrial sector from natural gas to the more attractively priced fuel oil.

Mr. FUQUA. A lower price?

Mr. EVERED. Yes.

Mr. FUQUA. Mr. Mares, how much new gigawatt capacity is going to be needed by 2000 to replace the plants that are scheduled to retire or because of new capacity needs?

Mr. MARES. Well, it depends on what you want to assume in terms of the growth in demand as well as how well the firms are able to continue to upgrade their existing capacity. There is a series of projections in the energy policy study. If we take the assumption of a 3-percent growth in demand and an extension in the useful life of the facilities, if I recollect, it is 45 years, the total supply that would be needed by the year 2000, at 3 percent per year growth in demand would be 438 gigawatts.

Mr. **Fuqua**. Now, how closely is that tied to the GNP growth?

Mr. **Mares**. It assumes a GNP growth of about 3 percent.

Mr. **Fuqua**. So it is almost parallel?

Mr. **Mares**. It happens to go almost parallel.

Mr. **Fuqua**. Would that take care of retiring plants? Is that new capacity or would that take care of retiring of power stations?

Mr. **Mares**. It takes care of retiring economically obsolete facilities. It recognizes that current oil-fired and gas-fired facilities are not as economically attractive on a long-term basis as either coal or nuclear. So it contemplates the replacement of higher costs of existing facilities by lower cost base facilities. It also takes into account retiring old, physically obsolete facilities.

Mr. **Fuqua**. Dr. Willis, which areas of the R&D continue to have the strongest support? I am talking about energy R&D, of course, among IEA member countries and has there been a decline in support for solar and renewable and conservation R&D abroad as there has been here or funding for those projects?

Dr. **Willis**. The answer to the first part of your question, is that it's quite clearly the nuclear area. It very much mirrors the United States experience in the numbers that Dr. Rivlin gave this morning—the same sort of proportions. If you take the six out of the seven summit countries excluding France, which is not a member of the IEA, the total investment in nuclear related, that is advanced nuclear, including fusion and breeder plus the conventional nuclear which is the back end of the fuel cycle, safety and so forth, about two-thirds of the total IEA energy R&D investment goes into that area of broad nuclear.

The second part of your question about asking has the investment declined in other countries in solar, conservation and renewables, the answer is that there is considerable variation. In general, it has not gone down in renewables. Conservation has always been rather a mixed bag. The Japanese, for instance, have put very, very little of their government money into conservation from about 1976. The Japanese have traditionally used the marketplace for determining conservation investment. Other countries, particularly the Nordic countries and Germany, by contrast, have put more money in and kept it up, increased it, if anything this year.

The renewables in other countries generally have kept up their base levels but they were never anything like the enormous excursions that we had in this country in the late seventies. So while ours has gone down, it is still a very big effort compared with other countries.

Mr. **Fuqua**. Do you want to ask some questions while I go vote?

Mrs. **Lloyd**. Yes.

Mr. **Fuqua**. We have a vote on right now and I recognize Mrs. Lloyd. She will have to quit after a while, but I hope I will be back and other members will be back to resume the questioning.

Mrs. **Lloyd** [presiding]. First of all, I would like to commend all of you for your very fine testimony. You certainly did an excellent job. I appreciate your being with us today.

Mr. Mares, electricity prices have been increasing about 4 percent annually in real terms since 1970. At the same time, we have seen the oil, gas, and coal prices increase from about 9 to 16 percent. Do you think that this disparity in the growth rates for fossil fuels has increased industries' turn to electricity as alternative to these sources? How do they relate?

Mr. MARES. I think that the motivation to use electricity will continue to be high relative to the use of other energy sources, particularly when compared with gas and oil.

Mrs. LLOYD. You think cost is a factor for the increased use of electricity.

What is your department's conclusion with regard to the relationships between the growth in energy and the growth in our gross national product?

Mr. MARES. We used, in our analysis, as a result of evaluating it, about a one-to-one multiplier for the ratio of electricity growth to economic growth. But, that is not an inherently rigid multiplier that might not change. In fact, it has changed over the last several years but at least the projections based on our analysis——

Mrs. LLOYD. I am talking about electrical energy.

Mr. MARES. That is correct. We used for electrical energy and GNP growth the general assumption that as a result of our analysis that if GNP grew at about 3 percent real, that electric demand would grow at about 3 percent real and that is giving you a conclusion without giving you the backup analysis which was described in some detail in the policy report that was made.

Mrs. LLOYD. So you say parallel growth for GNP and electrical energy?

Mr. MARES. Correct.

Mrs. LLOYD. Dr. Rivlin, I appreciate your comments about the antitrust problems in industry R&D endeavors. I think this is very timely because Congressman Sensenbrenner and I are introducing legislation today to address this issue and I am hopeful that it will solve some of the problems in this area.

I notice that you mentioned on page 9 of your testimony that nuclear development expenditures have increased. Does this include expenditures for our enrichment program? This is totally financed, as you know, by user fees.

Dr. RIVLIN. Yes, we noted that it is financed by user fees, but it is included in the total.

Mrs. LLOYD. So the user fees are included in our total as well?

Dr. RIVLIN. The user fee programs are included in the total.

Mrs. LLOYD. Has development in nuclear area increased if user fees expenditures are excluded?

Dr. RIVLIN. That is a gross number that we have. We would have to subtract that out and supply the answer for the record, if we may.

Mrs. LLOYD. Very fine.

[The information follows:]

Even if the user-funded R&D programs of the Department of Energy are excluded, current-dollar spending for nuclear programs was higher in the fiscal year 1984 budget than in the fiscal years 1983 and 1980. As my testimony points out, though, funding has been shifted away from development, so that 1980 nuclear development spending exceeded the proposed 1984 level. In any case, these results are not affected by the elimination of the user-funded uranium enrichment program, as is shown in the accompanying table.

TOTAL BUDGET AUTHORITY FOR NUCLEAR R&D (FISSION AND FUSION) IN FISCAL YEARS 1980, 1983, and 1984 a/ (in millions of current dollars)

	With Uranium Enrichment	Without Uranium Enrichment
Basic Research	2.0	0.8
Applied Research	196.6	192.9
Development	1037.4	913.7
1980 Total	1236.0	1107.4
Basic Research	2.6	2.4
Applied Research	391.6	390.6
Development	804.0	683.3
1983 Total	1198.2	1076.3
Basic Research	1.9	1.7
Applied Research	411.1	410.2
Development	873.7	742.4
1984 Total	1286.7	1154.3

a. Data refer to the Administration's January budget proposal, prior to amendment by the Congress.

Mrs. **Lloyd**. Another question on the nuclear issue: Since this is a very complex technology which has enormous potential, doesn't it really warrant more funding than the other alternatives like conservation which are not so scientifically sophisticated? There are certainly more expenditures in relation to the nuclear industry than in conservation.

Dr. **Rivlin**. It depends on one's focus. Really, one should look at the potential payoff in energy saving or in oil saving if that is the focus over the long term to conservation and to other sources of power. Certainly so far as research goes, the complexity of the problem probably warrants more expenditure but I am not sure that it follows at the development level.

Mrs. **Lloyd**. I would like to continue. I am going to have to leave for a vote also so we will resume our hearings shortly. Thank you very much.

[Brief recess.]

Mr. **Fuqua**. The meeting will resume.

Because of the interruption and the other members are not here, other members may want to submit some questions in writing to you.

Mr. Lewis.

Mr. **Lewis**. Thank you, Mr. Chairman.

Dr. Willis, I was frankly impressed with your testimony on fossil fuels and you said in your testimony that fossil fuels will inevitably decline, although their time frame is more extended than we may have imagined in the early seventies. I have a great concern about this, as you recall, and most of us do, that back in the sixties we had much research going on that we were running out of fossil fuels and we had like a 25-year forecast at that time that it would become critical. Then in the early seventies, before OPEC, we had an 18-year projection, I believe. Now we are saying it may be extended again.

Are we really fooling ourselves or have we come up with a better method of determining how long we will have the availability of fossil fuels?

Dr. **Willis**. It is quite clear that there was more fossil fuels available than we thought at that time and indeed, yes, the energy R&D picture was driven by exactly the supposition that we were going to fall off a cliff maybe as early as 1990. Quite clearly that is not true today. What is true, however, is our awareness that our economies are astonishingly vulnerable to interruptions in supply and possibly, the international energy R&D picture is being driven as much by the energy security aspects as the fact that fossil fuels are running out.

In the long term, we obviously have to plan for the time when we don't have as much oil around and that will come with a breeder or fusion energy in the future. We have to plan for that. We have to plan for the use of coal which will not run out as fast as oil will, and eventually we may have to have some synthetic fuels. But more importantly, we are very, very concerned in the framework of the nineties, for instance, with the diversification of supplies because of what has happened to our economies as a result of these oil shocks. They have been really very serious, and they are having their effect in the roles of the unemployed. Energy R&D, I think, has got to be geared as much to energy security in the nineties as it has been in the past to the decline of fossil fuels, particularly oil.

Mr. LEWIS. To continue on the fossil fuels situation, do you feel that our petroleum chemical companies and petroleum companies are making a great mistake or putting themselves in jeopardy? If you recall just a few years ago, alcohol fuels were certainly the synfuels of the future to some extent, and legislation was passed in a number of States—I passed legislation in Florida to allow gasohol usage—and other States did the same thing. And then we allowed tax credits for the use of gasohol and also to those that manufactured it.

We now are eliminating these sort of credits and making it so that gasohol and those kind of products are no longer competitive to some extent with fossil fuels but we also find that the petroleum companies are more interested in selling a super unleaded fuel, which would be at the same price more or less as a gasohol fuel. Would you like to comment on that?

Dr. WILLIS. That is a good one.

Mr. LEWIS. Mr. Mares would like to comment on it.

Mr. MARES. I spent 18 years in the petroleum chemical industry. I grew up in it and I would say the answer to your question is that no, I don't think that industry is at all disadvantaged or worried about the change in approach and diminishing the support for alcohol fuel. I think they have put in a lot of money and done a lot of things in that area. For instance, the Eastman Kodak Co., has in place a commercial gasifier to convert coal into synthesis gas to make acetic anhydride, which is used to make some of their basic chemicals. Other firms have a lot of research underway to convert synthesis gas derived from coal, or today could be derived from natural gas, or from oil into a variety of chemicals.

So, no, sir, I do not despair for the petrochemical industry in this country.

Mr. LEWIS. Dr. Willis.

Dr. WILLIS. That is very close to my own views, Mr. Lewis.

Mr. LEWIS. Mr. Chairman, I would like to ask Mr. Mares and Mr. Evered a question on the impact of natural gas deregulation on future gas prices. For example, what are the DOE and EIA, what are their current projections based on deregulation and if there is a discrepancy, what are some of those reasons for the differing projections and how closely to the EIA forecast does the DOE's energy policy plan correspond in energy projections?

Mr. MARES. There is a difference of view between the Policy Office at the Department of Energy and the Energy Information Administration about the implications of the administration's proposed bill. Rather than to get into the details of whether those differences exist, because it is a rather complicated story, I would be prepared to provide you with an analysis that I submitted to the Secretary that indicates the reasons that we believe that difference exists.

Generally, we believe the price of natural gas will be lower than EIA would project.

Mr. LEWIS. I see.

[Attached for the record is a copy of the analysis prepared by the Office of Policy, Planning and Analysis of the Energy Information

Administration (EIA) study of "The Natural Gas Market Through 1990: An Analysis of the Natural Gas Policy Act (NGPA) and Several Alternatives, Part IV."]

Department of Energy
Washington, D.C. 20585

May 19, 1983

MEMORANDUM FOR The Secretary

FROM: Assistant Secretary for Fossil Energy and
Acting Director for Policy, Planning and
Analysis

SUBJECT: Part IV of the EIA Study

The Energy Information Administration (EIA) study of The Natural Gas Market Through 1990: An Analysis of the Natural Gas Policy Act (NGPA) and Several Alternatives, Part IV, was sent to the printer on May 18, 1983, and is scheduled for public release on Monday, May 23. I must advise you that the EIA analysis of S. 615 is fundamentally flawed and misleading and does not provide a reliable basis upon which to make important policy decisions concerning Federal regulation of the natural gas market. The more noteworthy defects of the EIA analysis may be summarized as follows:

(1) The results of the EIA study are based on a new, unevaluated gas market model that does not, and cannot, represent the free, competitive market for natural gas that the Administration's proposal is designed to secure.

(2) Several major assumptions were used that are generally recognized to be incorrect by both supporters and opponents of the Administration's proposal. These assumptions include:

-- irrational pipeline behavior;
-- no excess deliverability of low-cost gas;
-- no reserve additions due to old gas price deregulation;
-- limited fuel switching capabilities in the utility and industrial sectors.

(3) A distressing lack of objectivity in EIA's discussion of the provisions of the Administration's proposal.

Contrary to normal Departmental practices, EIA has not responded to the requests of the Office of Policy, Planning and Analysis for the detailed backup data explaining the EIA study. Nonetheless, I am confident that my initial conclusions are accurate. They are based on a review of the EIA study by DOE analysts who are intimately familiar with the operations and economics of the natural gas industry and with all major computer models of that industry. In addition, the EIA study's conclusion that prices under S. 615 would rise above NGPA price levels is contradicted in GAO's analysis of S. 615, Report To The Subcommittee On Environment, Energy And Natural Resources, House Committee On Government Operations, An Analysis Of Natural Gas Pricing Policy Alternatives, Vol. II.

New, Unevaluated Model

The EIA gas study is based on results from the new Gas Analysis Modeling System (GAMS). The GAMS model has not been published before now and has not been subjected to peer review of its structure and logic, either within or outside the Department.[1] Appendix C of the study indicates that the model has only been compared against the natural gas market experience of 1980 to 1982 for validation purposes. Also within the text of Part IV there are several assertions made that the gas market cannot function smoothly. I find it incredibly unfortunate that EIA, in designing a model to evaluate natural gas decontrol options, did not look to the experience of the deregulated intrastate natural gas markets in Texas, Louisiana, Oklahoma, New Mexico and Kansas for the pre-NGPA period which shows that gas markets can work well. Such a review is particularly critical given the regional detail in the model and the fact that the pre-NGPA intrastate experience is the only body of unregulated market experience for the past 30 years.

I also am disappointed that neither the Executive Summary nor the body of the study includes the key points of Appendix A that this model is "a new approach" (page 85) or a "break from the more traditional modeling approach" (page 96) or the limited review the model has received. By far the most effective check on model validity is through circulating its description and results for review by others doing similar work in the field. Unfortunately, it is my understanding that problems of complexity and time prevented EIA from taking this critical step.

Our review shows that this model is structurally incapable of depicting either current market conditions under the Natural Gas Policy Act (NGPA) or the operation of a free gas market

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1/ Only the supply module (PROLOG) of the GAMS has been widely circulated for review.

under the Administration's proposal. The GAMS model depicts a complex network of producers, pipelines and end users (over 4,000 separate markets). In the process of simulating gas flows and prices in these markets, GAMS arbitrarily constrains a large number of the flows and prices at close to historical levels. This means that major changes, such as we are experiencing today, cannot be accurately modelled; and the more dramatic shifts we would expect as we move to a free market under the Administration's proposal cannot be captured. This includes shifts to least cost reserves, use of low-cost deliverable supplies that currently are shut-in, and shifts among substitute fuels.

Inaccurate Assumptions

The EIA results are incorrect because the GAMS model was run using four assumptions that are generally disputed by both supporters and opponents of S. 615. EIA assumed:

(1) Irrational pipeline behavior;

(2) No excess deliverability of low cost gas;

(3) No reserve additions due to deregulation of old gas prices; and

(4) Limited fuel switching capabilities in the utility and industrial sectors.

Correction of any one of these assumptions would likely change the results of the EIA study dramatically; all four of these assumptions would have to be changed before the results would be credible.

Irrational Pipeline Behavior

EIA assumed that under S. 615 no contracts would be renegotiated until 1985 and that in 1985 all contracts would be rewritten. Rather than assuming that these renegotiated contracts would require pipelines to pay the price at which gas supply equals gas demand, EIA incorrectly assumed that pipelines would tend to pay the "bid price for new gas" for all their gas supplies. They assumed this even though the bid price is $0.80 to $1.50 per mcf above market clearing in 1985.

The bid price for new gas is an output from the inadequately documented portion of GAMS that predicts pipeline behavior. This critical component of the model predicts that pipelines will make irrational decisions to pay more for gas than they need to. In fact, during the late 1980's this component of the model predicts that pipelines will sign long-term contracts for gas reserves at one price even though the model predicts that they could secure those same reserves at a lower price the following year.

No Excess Deliverability of Low-Cost Gas

An excess of deliverable, low-cost gas supplies is a phenomenon of rigid NGPA prices, reduced demand, and a regulatory framework that penalizes pipelines for reducing contracted supplies of high-cost gas. The result is a well-documented supply of low-cost gas that is currently shut-in; however, EIA assumes no such excess deliverability. Current estimates indicate a minimum of 1.5 tcf of supplies that producers would be willing to sell at prices well below the price of crude oil. Even the American Gas Association (AGA), an opponent of S. 615, estimates that 2.7 tcf of gas is shut-in (Natural Gas Production Capability - 1982, AGA, December, 1982).

The GAMS model assumes that any excess deliverability of supplies will be brought to the market only if they receive 110 percent of the Btu equivalent price of crude oil or almost $6.00 per mcf given current oil prices. Much of this surplus is old gas with a current average price of $1.00 to $1.50 per mcf. It is unrealistic to assume that gas that is currently available at one-quarter the Btu equivalent price of oil would flow to market only at 110 percent of that price.

No Old Gas Supply Response

The EIA study assumes no additions to old gas reserves as a result of deregulation of wellhead prices. Virtually all other studies of natural gas deregulation--including those by critics of deregulation--see some increase in old gas reserves. These range from the Consumer Federation of America/Independent Gas Producers estimate of 5.7 tcf to the Shell estimate of 52 tcf. DOE estimates are in the 8.5 to 11 tcf range, with potential to go much higher.

In a two sentence paragraph buried on page 55, EIA notes that the issue requires "further detailed study." The requirement for further study is not mentioned in the Executive Summary, and no mention whatsoever is made of the potentially dramatic effect that the omission of an old gas supply response has on the results.

Limited Fuel Switching Capability

EIA's May 1983 Annual Energy Outlook (AEO) documents significant fuel switching capability and concludes that significantly more fuel switching will occur if gas prices continue to rise. The AEO projects a decline in natural gas consumption by 3.7 tcf in the utility and industrial sectors between 1980 and 1985 and directly attributes 2.5 tcf to fuel switching as residual fuel prices become competitive with natural gas under NGPA. The AEO projections contradict the EIA/GAMS result. The AEO projects under NGPA 3.2 tcf less gas consumption in 1985 than EIA/GAMS and 2.0 tcf less gas consumption in 1990.

The only possible conclusion in the face of this evidence is that the EIA/GAMS study is wrong, either because it projects gas prices that are far too high (above residual fuel prices) or by assuming far too little fuel switching capability. DOE's analysis concludes that fuel switching would be limited under S. 615 as the potential for such shifts would force pipelines to lower prices in order to maintain industrial and utility load.

Consumer Prices and Impacts on Households

EIA predicts that in 1985 residential gas prices will be 6 percent higher under S. 615 as compared to NGPA. In 1990, prices would be 7 percent higher. These predictions follow logically from EIA's assumptions that average wellhead prices will rise under the Administration's bill, and are wrong for the same reasons discussed above--EIA's price predictions are generated by a flawed model using incorrect assumptions.

Objectivity of EIA Analysis

In Section 2 of the EIA study, which summarizes the provisions of the NGPA and several alternatives, the discussion of S. 615 is far less objective than the summaries of the Gephardt, Slattery, Addabbo or other proposals. In several cases, the editorial conclusions are unfounded and incorrect. The two most egregious examples are:

- The discussion of the PGA limitation which characterizes this provision as "...retroactive ratemaking, which is not current practice and generally considered to be a bad ratemaking procedure." The PGA limitations in no way constitute retroactive rate making. This entire discussion shows substantial lack of understanding of current NGA/NGPA ratemaking procedures, and it ignores the major benefits to consumers of placing both pipelines and producers on notice that high gas costs will not automatically be passed through to consumers when lower cost supplies are available.

- The discussion of contract carriage asserts that the provision would "...create a strong incentive for interstate pipelines to get out of the reserves ownership business and into transportation of gas." It further states the "...additional profits of about a billion dollars annually are potentially available to the pipelines under this option." Both assertions are patently ridiculous. In three weeks of Senate mark-up on contract carriage, the question of pipeline incentives to give up ownership of gas reserves and become strictly transporters of gas was never raised. Furthermore, in order to reach $1 billion annually, pipelines would have to be receiving the $.05/mcf incentive on substantially more gas than they are transporting annually.

Summary

The EIA study is based on a new, unevaluated model of the gas market that is unable to capture the effects of the current market conditions or the impacts of a free market. The flaws in the model are further compounded by assumptions that contradict well-understood gas market phenomena. Results of EIA's model contradict other recent EIA studies. The EIA study's representation of S. 615 is inaccurate.

As I obtain more information in my review, I will expand on this analysis.

Mr. Evered. We would be happy to provide for the record the relevant materials which address your question.

[The EIA has not compared its recently released report, "The Natural Gas Market Through 1990; An Analysis of the Natural Gas Policy Act and Several Alternatives, Part IV" to any other Department of Energy forecasts. However, shortly after release of the Part IV report, EIA received and responded to a series of questions concerning the report and its assumptions from Representative Tom Corcoran. Attached is a copy of that correspondence.]

TOM CORCORAN
14th District, Illinois

ENERGY AND COMMERCE
COMMITTEE
SUBCOMMITTEE ON FOSSIL AND
SYNTHETIC FUELS

POST OFFICE AND CIVIL
SERVICE COMMITTEE
SUBCOMMITTEE ON POSTAL OPERATIONS
AND SERVICES

COMMISSION ON CONGRESSIONAL
MAILING STANDARDS

Congress of the United States
House of Representatives
Washington, D.C. 20515

WASHINGTON OFFICE:
2447 Rayburn House Office Building
Washington, D.C. 20515
(202) 225-2976

ILLINOIS OFFICES:
115 Campbell Street
Geneva, Illinois 60134
(312) 232-0144

100 West Lafayette Street
Ottawa, Illinois 61350
(815) 434-0088

Illinois Toll-Free Action Line:
(800) 842-0837

May 24, 1983

Mr. J. Erich Evered
Administrator
Energy Information Administration
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Dear Mr. Evered:

I have recently reviewed a copy of EIA's study, The Natural Gas Market Through 1990: An Analysis of the Natural Gas Policy Act (NGPA) and Several Alternatives, Part IV.

The ability of this or any study that relies almost exclusively upon past gas market participant behavior to predict future activity in the gas market is very questionable. While this new EIA report may well be a sincere effort to predict the future, I believe it is fundamentally flawed.

The task is complicated when the proposal to be analyzed is not a different list of numbers such as new price ceilings, but an interrelated set of incentives designed to encourage response toward a certain objective, in this case a competitive and flexible natural gas market. As is pointed out in the study (p. 56), EIA has made three assumptions in projecting the price effects of the Administration's bill that cause higher wellhead prices than would otherwise be the case. As I will explain below, I think all three assumptions are wrong. I am confident that wellhead and, more importantly, delivered gas prices will be lower under the Administration's proposal than EIA has suggested.1/

Unfortunately, when Congress is dealing with an emotional and politically charged issue like natural gas legislation, numbers and studies become critical. The output of the battle of models and econometricians becomes so much ammunition to be fired at the "other side." In the process "the bottom line" is all thet is important even when that bottom line is largely arbitrary and based on assumptions that are already wrong.

The Part IV Study recognizes that "[t]he probability that any projected numerical value will be realized is low..." (p. 3) The model may contain inaccurate assumptions. Data may be wrong. And a model, as the study points out,

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1/ The General Accounting Office, in a letter report to Senator James McClure dated April 11, 1983 agreed and stated that wellhead prices would be 27¢ to 40¢ lower per thousand cubic feet (or, mcf) under the Administration's bill than those projected to occur under their analysis of the NGPA.

is "by definition, an abstraction of reality." The Part IV Study does not even contain complete documentation of the "modeling process" upon which its conclusions are based. That, we are told, will be published separately.

I am not an economist and have no great experience in analyzing models. That is for others to do, preferably before it is used. From my reading of the Part IV Study, however, it appears to me that the GAMS model is already at substantial variance from the market which it is supposed to be modeling.

Please forward to me the independent evaluations of the GAMS model that have been done, if any. I would also appreciate your response by June 6, 1983 to the following questions:

1. To what extent does the GAMS model assume that natural gas subject to the NGPA will not be sold at prices less than NGPA ceiling prices?
2. Why does the model assume that natural gas in storage is totally drawn down in the winter and what distortions result if that does not happen?
3. To what extent does the GAMS model assume adherence to long term gas contracts by the parties?
4. What amount and kinds of renegotiation are built into the GAMS model? By renegotiation, I mean both voluntary contract adjustment and "involuntary" change in gas supply and/or pricing due to the use of force majeure clauses, market out clauses or the bargaining leverage that purchasers have in a buyers' market (see e.g., recent Tennessee pipeline action).
5. What is the justification for treating the pipelines' purchase of gas reserves as a market separate from the pipelines' purchase and sale of natural gas to consumers? What is the effect of this treatment on EIA's analysis?
6. To what extent does the model reflect the results of gas "brokering" by pipelines? By brokering I mean systems of the kind now being used, or about to be used by Transcontinental pipe line, Panhandle Eastern Pipe line and others?
7. To what extent does the model project that pipelines will bid more than market clearing prices for natural gas?

Wholly apart from the ability of the model to simulate a more flexible natural gas market where gas must compete directly with oil, I have a number of questions about the assumptions EIA made, especially those used in applying the model to the Administration's natural gas proposal.

1. What is the justification for assuming that gas distributors "have no decision flexibility on gas purchase prices?" Is this assumption made in analyzing all the legislative proposals regardless of the kind of contract carriage provisions they contain?

2. What is the justification for EIA's assumption that under the Administration's proposal no gas contracts will be renegotiated until 1985? Why didn't EIA at least make an alternative projection assuming some renegotiation prior to 1985?

3. Why did EIA assume that once 1985 came, all contracts would be rewritten up to new contract prices? Why didn't EIA make an alternative projection assuming that some old gas would continue to be priced less than new gas because it simply isn't worth as much due to the age of the reservoir, the volume of gas deliverable per day or due to the advantage to both producers and purchasers of maintaining existing buyer-seller relationships?

4. What current excess deliverability of low cost gas does EIA assume? How long does EIA project that the market will be characterized by excess deliverability? At what price does EIA assume that the gas currently shut in as excess deliverability will be sold?

5. Why does EIA assume no additions to old gas reserves as a result of deregulation of wellhead prices? What is the basis for the statement that "the NGPA has provisions to permit such old gas response", especially given the practical and political difficulties involved in using this permission? At least, EIA could have made an alternate projection using the DOE's estimate of 8.5 to 11 TCF.

6. Why does EIA in this study project more gas demand in 1985 (3.2 TCF) and 1990 (2.0 TCF) than EIA did in its April 1983 Annual Energy Outlook?

7. Why does EIA assume that LNG imports by Trunkline do not start until 1984 when in fact they began in October 1982 and are having a major price impact on consumers served by Panhandle and Trunkline pipelines? Why does EIA presume that Columbia and Southern Natural Gas Company will resume importing LNG in 1985?

There are so many points at which another assumption appears to be at least as reasonable, if not more reasonable, than those employed in the Part IV Study. It seems to me imperative that EIA produce additional analysis using the alternatives outlined above. Only then can we clearly see the impact on EIA's conclusions of the choice of one assumption rather than another.

I would like to think that the consistent choice of assumptions most negative to the Administration's proposal and the failure to depict any alternatives is not deliberate. After reading EIA's summary of the Administration's proposal, however, I doubt that, especially when that summary is compared with the summaries of other natural gas proposals.

A few of many possible examples illustrate my point. The Study states that the transitional pipeline pass through cap contained in the Administration's proposal "may constitute retroactive ratemaking, which is not current practice and generally considered to be bad ratemaking procedure." Number one, it is true that costs above the pipeline's allowed rate must be approved before they can be passed through, but pipelines are aware of this when they incur such costs. To characterize such review as "retroactive ratemaking" imparts a new meaning to the word retroactive. Number two, yes, this is a change from the current automatic pass through of everything subject to refund practice. As any consumer will tell you, current practice has been bad ratemaking procedure, as far as they are concerned. Number three, subjective editorial comments like this have nothing to do with an objective description of what the proposal does.

Second, the discussion of contract carriage does not stop at describing the provision and how it would operate. Instead, the contention is made that there would be "a strong incentive for interstate pipelines to get out of the reserves ownership business and into transportation of gas," and that "additional profits of about a billion dollars annually are potentially available to the pipelines under this option." No evidence or projected likelihood is offered for either of these propositions. As far as the first goes, it is not even clear what conclusion we are to draw from this. Many of my colleagues are disturbed about pipeline producer affiliate transactions and would be just as happy to see the pipelines focus on what they are paid to do: transport gas. With notable exceptions, pipelines have not supported contract carriage as contained in the Administration's bill. Perhaps EIA had better tell them how much they are throwing away.

Again, the most disturbing aspect of these comments is not that they are wrong, but that they were made in what is supposed to be an objective evaluation of several natural gas legislative proposals.

As a final example, the Report asserts that the development of a gas spot market, which would lower the prices projected under the Administration's proposal, "is difficult to defend because historically gas markets have operated under long term contracts." (p. 55) That has not been true even historically in the deregulated intrastate markets. Why assume that the features of a regulated market will carry over into a deregulated market rather than looking at the intrastate experience? Moreover, developments over the past few months demonstrate that the spot market in gas is already beginning. To ignore these developments is to ignore reality.

I ask you to compare remarks like these with the descriptions of the other proposals. Rather than describing the potential problems that are raised by the permanent and complete elimination of commodity based price escalation, as the authors apparently thought was appropriate to do with regard to the Administration's proposal, the authors volunteer that the Gephardt bill "does not specifically rule out periodic renegotiations." They add that "contracts calling for periodic renegotiation were more frequently found in intrastate pipeline contracts prior to the NGPA." We are not told the relevance of this point to the Gephardt bill or the analysis of that bill. If the authors are suggesting that we could expect more frequent renegotiations under a bill which extends regulation because such renegotiations existed in a market not subject to any Federal regulation, I don't buy it. And I do not see what it has to do with describing what the proposal does.

In conclusion, I am troubled by what seems to me to be a deliberate effort to describe the Administration's proposal as negatively as possible while viewing others through more rose-colored glasses. I sense a skepticism and rejection of the unquantifiable, of something that deviates from the historical pattern. This is understandable, and even common; a number of my colleagues have expressed similar doubt. When it infects the bottom line of a supposedly objective study, however, it is wrong.

In this case, it appears to me that it has.

I look forward to your response to help me better understand the Study and why certain assumptions were made.

In addition, I am most interested in learning your personal involvement in the preparation and review of this most important study, including the documentation of the dates upon which you supervised each stage of its development and resolution. I have never sought to influence the work at EIA nor am I aware of any attempt to do so by the Secretary's office. That is your responsibility under the Department of Energy Act and I am interested in making sure it has been discharged in good order. If you would like to meet with me about this, please call me and we will arrange a mutually convenient time.

Sincerely yours,

Tom Corcoran
Representative in Congress

cc: The President
The Secretary of Energy

Department of Energy
Washington, D.C. 20585

June 1, 1983

Honorable Tom Corcoran
House of Representatives
Washington, D.C. 20515

Dear Mr. Corcoran:

Thank you for your letters of May 23 and 24. We will be happy to include Congressman Sharp's proposal among those which are currently being analyzed, as you requested. The exact details and schedule for the analysis will be worked out with your staff. We are pleased to be of service.

As for the analyses of existing law (NGPA) and the Administration's proposal which were presented in our recent report--The Natural Gas Market Through 1990: An Analysis of the Natural Gas Policy Act and Several Alternatives, Part IV--I am afraid you may have been misled concerning both the intent and the conclusions of the study.

We stand by the report, and are confident in the analysis and its conclusions based on the fully disclosed assumptions. Detailed responses to each of the enumerated questions and concerns in your letter of May 24 are contained in the enclosure to this letter.

Background

The Part IV report is the fourth in a comprehensive series begun over two years ago in anticipation of the need for detailed, objective information and analysis on natural gas markets. This study is not an attempt to predict the future. Like all of our projective analyses, its purpose is to shed light on the dynamic interactions of complex energy markets and to display the likely consequences of various energy policy alternatives under specified assumptions concerning key factors which influence the market. There are many alternative sets of assumptions which might be employed in any such analysis. We winnowed the possibilities carefully to arrive at the particular set used; they represent the Energy Information Administration's (EIA) current best judgment at the time of the report's preparation. Any reasonable alternative assumptions can also be evaluated, and we would be pleased to do so at your request.

The GAMS Model

The analyses presented in Part IV were conducted using as the principal tool the Gas Analysis Modeling System, or GAMS. We believe the GAMS model to be the best representation of the natural gas market available and it significantly advances the state-of-the-art in modeling natural gas markets. Yet, it is not perfect and we work continually to improve it. Since this is a different approach to modeling the natural gas market, we have tried to alert the reader of Part IV to this issue. Brief statements of the methodology and critical assumptions are available (see p. viii, 2 and 35). Further, Appendix A provides 25 pages on the model methodology for the non-technical reader.

With respect to the GAMS model used in the study, written documentation has not yet been completed, and written independent evaluations do not yet exist, although major parts of the model--such as the PROLOG and OCS submodels--are documented. The model has not been developed in secret, however. Presentations have been made at a national meeting of the Operations Research Society of America and the Institute of Management Science, and at a Workshop on North American Gas Markets at Stanford University. Additionally, presentations and working group meetings on GAMS over the past year and a half have been attended by personnel from the Department of Energy (DOE) Office of Policy, Planning and Analysis, and the Federal Energy Regulatory Commission (FERC). Lastly, meetings have been held with trade group representatives and other organizations where the basic structure of GAMS has been discussed and favorably commented on.

In line with EIA's consistent and continuous policy, the entire model will be fully documented, archived, and made available to the public as soon as practicable. This practice is followed by few if any other organizations. While it would be worthwhile to document and validate all models before their first use in analysis, it is impracticable and is rarely done.

No Bias in the Analysis

I emphatically deny that the analysis was conducted or the report written with any negative bias toward the Administration proposal. Allegations to the contrary ignore the strong statements favorable to the proposal contained in the report (see, for example, pages xvi, 49, 55 and 73). I take very seriously EIA's responsibility to conduct its analyses in an objective and supportable manner. The Part IV report was prepared in just such a fashion.

In retrospect, you are probably correct that the report should not have contained comments on the Administration proposal bordering on the subjective or editorial. They were intended solely as useful additional information on the only actual legislative proposal analyzed in the report. (Were other proposals analyzed in Part IV, the reader would no doubt have benefited from such elaborative comments on them as well.)

Additional Analysis

We agree that sensitivity analysis is important and we will examine the issues that you have raised. The other proposals were not fully analyzed in the publication. A supplement to Part IV responding to Chairman Sharp's request for analyses of the proposals introduced by your colleagues, Messrs. Gephardt and Addabbo, will be available soon.

Long-term Nature of the Market

An area of clear disagreement is how the natural gas market would behave upon passage of the Administration proposal. It is our judgment that, even under widespread decontrol, the natural gas market will operate under some of the same basic principles. Foremost among these is that pipeline companies will continue to secure reserves under long-term contracts to serve their customers. Prices bid for reserves will reflect the competitive nature of the market for those reserves, and the pipelines' judgment of the marketability of the gas over the life of the contract.

On the matter of the historical behavior of the unregulated intrastate market, you have plainly been misinformed.

The pre-NGPA intrastate market was indeed a long-term contracts market (see Intrastate and Interstate Supply Markets Under the Natural Gas Policy Act and Natural Gas Producer/Purchaser Contracts and Their Potential Impacts on the Natural Gas Market). In 1978 less than three percent of the quantity sold in the intrastate natural gas market was under short-term contracts (1 year or less) and over two-thirds was sold under contracts of 15 years or longer. Further, international gas markets are characterized by long-term contracts.

We have tried to lay out the issues on wellhead contracts and spot markets as we saw them at the time the report was written (see pp 22-26). We also have a study in progress which will present additional information and analysis on this issue.

Standard Procedures Followed

As with all EIA publications, our established internal review procedures were followed for this study. After preparation of a report by the appropriate program office, the report is reviewed and cleared by all EIA office directors. After the internal review and clearance the report is sent to the Administrator's office for final review and clearance prior to publication.

You will recall that in January I scuttled a final draft of Part IV that was based on stale data and assumptions invalidated by recent events in the world oil market. I received a draft of Chapters 1, 2, and 3 and Appendices A and B of the new Part IV for review on April 22, 1983; the balance of the report, including the findings and discussion of the analysis, was delivered to me on May 13, 1983.

EIA's Gas Information Activities

The Energy Information Administration has a statutory responsibility to serve policymakers' and decisionmakers' needs for timely, high-quality energy information and objective analysis of energy trends and projections. When I took over the helm of EIA two years ago, it was clear that the natural gas market would assume a high profile on the legislative agenda. We immediately set out to fill the major gaps in our (and everybody else's) knowledge and understanding of the gas market.

After an assessment of the state of the natural gas market (the Part I report), we researched and published a landmark examination of the much-discussed but little-understood "contracts problem" in Part II. Next came the highly acclaimed study of pipeline purchase behavior in Part III of An Analysis of the NGPA and Several Alternatives.

In order to serve better the data needs of analysts and decisionmakers, EIA introduced last fall the new Natural Gas Monthly, which consolidates previous publications and presents a broad range of important gas market data monthly, much of it never before published, and--significantly--does so with no increase in respondent burden in producing the information. Last month we published Natural Gas: Use and Expenditures, which gives detailed information by sector and region of the United States on who uses natural gas, what they use it for, and what they pay for it. All this is in addition to our regular and continuing production of natural gas information to serve the diverse needs of the FERC and others.

None of this happened by accident. These accomplishments are the direct result of the creativity and hard work of a cadre of skilled, dedicated, professional public servants in the Energy Information Administration. Severe constraints on staff and budget make these achievements all the more remarkable.

When we began these efforts two years ago, we realized that we did not have a modeling system adequate to evaluate rigorously the various impacts of proposed alternatives to current natural gas law. Hence, the genesis of the Gas Analysis Modeling System (GAMS), which was designed to fill that need and which represents a new generation in the state of the art of energy market modeling. As I said before, GAMS is the principal tool with which were generated the analyses presented in The Natural Gas Market Through 1990: An Analysis of the Natural Gas Policy Act and Several Alternatives, Part IV.

My intent with Part IV, as with all our information products, was to illuminate the debate over natural gas policy. Well, a lot of light has been generated, but unfortunately much heat as well. To the credit of the Department of Energy, the White House, and the Congress, none of that heat has been of a manipulative nature. Our independence, integrity and reputation are intact.

Recalling well Secretary Hodel's statements upon introduction of S.615 and H.R.1760 that the Administration's intent is to correct the deficiencies and inequities of the natural gas market under the NGPA, and that while the Administration's proposal is designed to do just that it is open to debate, negotiation and refinement, it has been my hope that the Part IV report and all of EIA's natural gas information products would be utilized constructively toward that end. That remains my hope.

With warmest personal regards,

(Signed) J. Erich Evered
J. Erich Evered
Administrator
Energy Information Administration

Enclosure

cc: The President
The Secretary of Energy

ENCLOSURE TO RESPONSE BY THE ADMINISTRATOR, ENERGY INFORMATION ADMINISTRATION, TO THE HONORABLE TOM CORCORAN, MEMBER OF CONGRESS; JUNE 1, 1983

Following are responses to your enumerated questions:

1. To what extent does the GAMS model assume that natural gas subject to the NGPA will not be sold at prices less than NGPA ceiling prices?

   Response: From a survey taken in 1981, we have estimated the proportion of contracts in existence during 1980 which specified NGPA price ceilings as well as the proportion which had more specific price terms. We estimate that contracts for approximately 20 percent of the gas flowing in 1980 had provisions which were not tied to price ceilings. Contracts for gas (signed after 1980) are assumed to be priced at the NGPA ceilings if the market is willing to pay the price. Further, we have attempted to update contracts information based on recent contract and PGA filings at the FERC.

2. Why does the model assume that natural gas in storage is totally drawn down in the winter and what distortions result if this does not happen?

   Response: Underground storage of natural gas in the U.S. is primarily designed to smooth out annual winter/summer consumption cycles. We think of the model as assuming that working gas (not all gas in storage) is totally drawn down each winter and then built up again each summer to starting levels. A more precise statement of the behavior embodied in the model would be that there is no net year-to-year change in gas in underground storage; i.e., however far storage is drawn down in the winter, that much is replaced in the summer of the same year. To the extent that this assumption is violated, there will be slight shifts in production between adjacent years but the overall trends will not be affected.

3. To what extent does the GAMS model assume adherence to long term gas contracts by the parties?

   Response: The types of contracts modeled in GAMS are explained in detail in the report (p. 95). In summary, it is assumed that the terms of long-term gas contracts in effect in 1980, as described by the EIA survey, are honored by the parties to the contracts until the gas is depleted or the contract expires. For new contracts we assume that upon deregulation both parties to the contract exhibit flexibility, with the effect that the gas is priced using the new contracts price as reference.

4. What amount and kinds of renegotiation are built into the GAMS model? By renegotiation, I mean both voluntary contract adjustment and "involuntary" change in gas supply and/or pricing due to the use of force majeure clauses or the bargaining leverage that purchasers have in a buyers' market (see e.g., recent Tennessee pipeline action).

   Response: Contracts with most-favored-nation (MFN) provisions with market-outs or periodic renegotiation clauses are assumed to be renegotiated yearly, using the new contracts price as a reference. Unilateral actions, other than market-out, on the part of parties to a contract are not modeled. (AMOCO, Chevron, Texaco, Superior and several other producers have filed suit, and Texaco and Conoco are seeking action at FERC against the Tennessee Pipeline's recent action.)

5. What is the justification for treating the pipelines' purchase of gas reserves as a market separate from the pipelines' purchase and sale of natural gas to consumers? What is the effect of this treatment on EIA's analysis?

   Response: The two markets are distinct, but loosely coupled. EIA believes that the acquisition of reserves under long-term contracts is based not just on current market conditions but also on demand and price expectations for years in the future. (This assumption is supported by the current behavior of many pipelines which have continued to contract for new supplies of gas despite the current surplus.) On the other hand, many consumers have the flexibility to alter their purchases without notice. The effect of this treatment is to significantly strengthen EIA's analysis over the approach of other models in which reserves acquisition is implicitly assumed to respond only to current market conditions.

6. To what extent does the model reflect the results of gas "brokering" by pipelines? By brokering I mean systems of the kind now being used, or about to be used by Transcontinental pipeline, Panhandle Eastern Pipeline and others?

   Response: Currently gas brokering is occurring on a very small scale. There is no specific representation of gas brokering within the current version of GAMS.

7. To what extent does the model project that pipelines will bid more than market clearing prices for natural gas?

   Response: In GAMS the market is always cleared, since supply is matched to demand at the prevailing price. On a year-to-year basis this clearing occurs within each pipeline system. In reality, pipelines never intentionally contract for production at greater than the anticipated market clearing price. However, some MFN or other commodity-tied clauses may force them into this position.

In response to your statement concerning flexible gas markets competing directly with oil, GAMS does indeed simulate a market in which gas competes directly with oil. Specifically, in GAMS gas competes directly with residual fuel oil in the industrial and utility sectors when the capability for dual-firing of boilers exists, and indirectly elsewhere. The size of the dual-fired boiler market and the conditions under which fuel-switching occurs are the subjects of continuing study, but the effects of uncertainty in this area can be analyzed by making alternate assumptions and evaluating the outcomes. A sensitivity analysis of the model to different sets of supply and demand assumptions was presented in Chapter 4. Unfortunately the combinations of parameter variations grow very fast and only a few could be selected for the analysis.

With respect to your other questions concerning EIA's assumptions:

1. What is the justification for assuming that gas distributors "have no decision flexibility on gas purchase prices?" Is this assumption made in analyzing all the legislative proposals regardless of the kind of contract provisions they contain?

   Response: Gas distributors, in general, purchase gas from pipelines whose tariffs are established by the FERC or a State Commission. This assumption is contained in the analysis of each legislative proposal in Part IV. Contract carriage is an issue which is not fully understood generally. How it would change the structure of the gas market is an important question. EIA has started a study of this subject, but we have no answers at this time. We are examining how freer markets that could be realized under the Administration's proposal might react. It is important to remember that contract carriage is neither common carriage nor deregulation of pipelines.

2. What is the justification for EIA's assumption that under the Administration's proposal no gas contracts will be renegotiated until 1985? Why didn't EIA at least make an alternative projection assuming some renegotiation prior to 1985?

   Response: EIA believes that the assumption of no renegotiation in 1984, or equivalently that renegotiations have no net effect on the projections, is plausible and likely. The rationale for our choice of assumptions in this case is straightforward. Producers are considered unlikely to make concessions to pipelines in 1984 and forego revenues unless they receive a higher-than-market price later. On the other hand pipelines are not likely to renegotiate low-cost contracts in 1984 unless they would continue to enjoy lower-than-market prices after 1984.

As with your other questions concerning alternate input assumptions, renegotiation prior to 1985 can be evaluated. However, if the multitude of alternatives which have been proposed were evaluated independently the combinations would become unmanageable. I encourage your staff to define a package of alternatives for key assumptions concerning the Administration's proposal which will represent your views of market behavior better than those chosen by EIA, so that the effect of these alternatives can be evaluated.

3. Why did EIA assume that once 1985 came, all contracts would be rewritten up to new contract prices? Why didn't EIA make an alternative projection assuming that some old gas would continue to be priced less than new gas because it simply isn't worth as much due to the age of the reservoir, the volume of gas deliverable per day or due to the advantage to both producers and purchasers of maintaining existing buyer-seller relationships?

Response: EIA does not believe that the age of a reservoir should influence the price of natural gas in a deregulated market, since the value to the consumer is the same, whatever the age. Further, maintaining existing buyer-seller relationships where better prices are available has limited value.

4. What current excess deliverability of low-cost gas does EIA assume? How long does EIA project that the market will be characterized by excess deliverability? At what price does EIA assume that the gas currently shut in as excess deliverability will be sold?

Response: EIA does not assume anything concerning excess deliverability of low-cost gas. The GAMS model solves for quantity. There is always some excess deliverability of gas. These and other assumptions concerning spot market sales are described in the report (see page 55). In the NGPA reference case analysis, there is some "shut-in" production under Sections 102, 103, 104, 105, and 107 in 1982 and 1983, each with quite different prices.

5. Why does EIA assume no additions to old gas reserves as a result of deregulation of wellhead prices? What is the basis for the statement that "the NGPA has provisions to permit such old gas response," especially given the practical and political difficulties involved in using this permission? At least, EIA could have made an alternate projection using the DOE's estimate of 8.5 to 11 Tcf.

Response: Any old gas supply response would be realized at the wellhead primarily in the 1990's and would probably not significantly change the results. The size of this response is directly related to the wellhead price. There are proposed rulemakings on this subject currently under consideration at the FERC.

EIA assumptions on the old gas supply response are stated in the report (see page 55). We believe the issue needs further study; alternative assumptions can clearly be made.

6. Why does EIA in this study project more gas demand in 1985 (3.2 Tcf) and 1990 (2.0 Tcf) than EIA did in its April 1983 Annual Energy Outlook?

   Response: The principal reason for much lower gas demand in the Annual Energy Outlook (AEO) is the large amount of oil substitution ("fuel-switching") in the industrial and electric utility sectors which takes place under AEO's higher gas prices. A more detailed description of the two cases, with their assumptions, model behavior and implications, is in preparation. However, it is important to remember that the alternatives discussed in Part IV were all evaluated using a single model and a consistent framework of market behavior.

7. Why does EIA assume that LNG imports by Trunkline do not start until 1984 when in fact they began in October 1982 and are having major price impact on consumers served by Panhandle and Trunkline pipelines? Why does EIA presume that Columbia and Southern Natural Gas Company will resume importing LNG in 1985?

   Response: Assumptions concerning imports seemed likely at the time they were made. Changing the assumptions would not significantly impact the aggregate results presented in the report although localized problems could occur.

In response to your additional concerns:

The assumption on the pipeline passthrough mechanism has been discussed with DOE's Policy and General Counsel offices and the FERC. After these discussions, EIA arrived at its decision. EIA is not alone in having trouble with the Administration bill's language. Chairman Butler and others have offered changes. In a market where market-outs are available, how can a pipeline keep its gas if it cannot pay the "market price" for it? EIA remains open to discussion on this issue.

On contract carriage, EIA believes the incentives are available under the Administration proposal, but the interstate pipelines have opposed this issue for over 50 years (see page 28). We are not sure why.

With other contract devices outlawed, periodic renegotiations would seem to be the only alternative to definite escalators. In addition, current ratemaking under Purchased Gas Adjustment (PGA) procedures is not good cost discipline for the market, as discussed in the report (see pp 26-30), since it allows for automatic cost increases with very little consideration for market response.

Mr. LEWIS. Thank you to the panel.

Thank you, Mr. Chairman.

Mr. FUQUA. Thank you, Mr. Lewis.

Again, as I say, we may have some other questions that we will submit in writing and we thank you all very much for being here this morning and sharing with us your thoughts on R&D pricing policy as they relate.

Thank you very much.

Dr. WILLIS. Thank you, Mr. Chairman.

Mr. FUQUA. Our next panel will be Joel Darmstadter, Resources for the Future here in Washington; Dr. Daniel A. Dreyfus, division director of strategic analysis and energy forecasting; Mr. Gene Oatman, manager of the energy resources department from EPRI—I might say Dr. Dreyfus is representing the Gas Research Institute—and Dr. Morris A. Adelman, professor of economics from a little school up in Massachusetts called MIT.

Mr. Darmstadter, if you want to lead off, we would be happy to hear from you, and if you want to submit your statements in the record and summarize, that certainly would be acceptable.

STATEMENT OF JOEL DARMSTADTER, SENIOR FELLOW, CENTER FOR ENERGY POLICY RESEARCH, RESOURCES FOR THE FUTURE

Mr. DARMSTADTER. That is what I would like to do, Mr. Chairman.

Representative Lloyd and Representative Fuqua, I appreciate being asked to contribute to your inquiry into the R&D consequences of changing perceptions about the Nation's energy future. I ought to mention at the outset that while my remarks are based on research conducted at Resources for the Future, on whose staff I serve as a senior fellow, I speak only for myself. Resources for the Future, as an institution, takes no position and makes no recommendations on policy issues.

In my testimony which I will try to summarize, I plan to address two broad topics:

One, how have U.S. energy consumption projections to the year 2000 and beyond changed in recent years and what are the principal factors accounting for those changes?

Two, what might be some of the implications for public policy and private-sector decisions as a consequence of shifting perceptions about long-term energy conditions?

I will touch only sparingly on specific R&D policy issues for that is a subject which other witnesses at this hearing, Mr. Dreyfus and Mr. Adelman, are more qualified to deal with.

Now, it is worth recalling that during the decade of the seventies, the art or science—depending on one's view of the matter—of forecasting energy demand approached the dimensions of a national obsession. There were probably two reasons for this development. One was the oil price shock of 1973-74 along with its reverberations to other energy sectors, which seemed to portend disturbances and discontinuity in the growth and structure of the economy, in technology, and in personal well-being. True, there had been intermittent earlier preoccupation with future energy adequacy and needs. By and large, however, such concerns did not endure: A condition of plentiful supplies and stable or declining real energy prices had been a fact of life for so long that its presumed permanence made long-range energy assessments unnecessary. In the seventies, this was no longer true.

The second reason for the proliferation of future outlook studies in the energy field goes back to an ideological phenomenon. Energy use was becoming a proxy for, on the one hand, the wherewithal for continued economic growth or, on the other, the route toward an ecological disaster. To the "expansionists"—flippantly characterized by some as the "dig we must" school—increased use of energy facilitated a rise in living standards; to the "limitationists," it simply intensified the growing problems of the environment, safety, and public health.

Still, the antithetical postures depicted above are not simply a caricature of positions that came to the fore in the course of the 1970's. Published energy-demand forecasts or "scenarios" diverged conspicuously depending on who made them. For example, a major 1975 study by the Edison Electric Institute—the trade association for investor-owned utilities—foresaw a level of primary energy requirements totalling 167 quads in the year 2000 if reasonable economic expectations were to be fulfilled. By contrast, Amory Lovins—a prominent environmentalist who, in many ways, personified the concern with "limits"—in 1977 argued the reasonableness of a year 2000 target figure of 100 quads or 40 percent lower. Philosophical positions clearly conditioned analysis. Even so, Lovins' forecast is likely to turn out to be much more accurate.

As of 1982–83, a good deal of the sound and fury accompanying the debate over energy in the 1970's has subsided. Why? The record of the last decade has helped shape such a toning down: The oil price shocks, while severely testing the resilience of the economy—indeed, contributing to the severe recession we have been experiencing—also demonstrated our clear-cut ability to use energy more efficiently when the cost of failing to do so was seen to be exceedingly burdensome. There has been a health process of demystification about energy: When the stakes are high, other productive resources and human ingenuity can serve as a partial, but very important, substitute.

These points come to life when we see, from these accompanying tables, how successive energy-demand projections for the years 2000 and 2020 have been progressively reduced. Table 1 shows U.S. Government projections for 2000 prepared at various intervals since the late sixties. Tables 2 and 3 contain the comparative results of a number of major efforts—undertaken between 1978 and 1982—to model energy demand substantially beyond the turn of the century.

A less bullish long-term economic prognosis is one of the explanations for those steadily reduced estimates. But the demonstrated potential for, and assumed further exploitation of, energy-efficiency opportunities is an equally, if not more, important reason. Between 1973 and 1981, the energy/GNP ratio fell at an average rate of nearly 2½ percent annually. So it is not unexpected that the most recent long-term forecasts, recognizing the adjustment underway in response to rising real energy prices, assume that continued—if decelerating—declines in the energy/GNP ratio will continue under the impact of the persistent price pressures embodied in the forecasts.

To summarize to this point: there has been a drastic scaling down of projected levels of energy consumption 20 and 40 years hence; and there appears to be diminishing divergence among different analysts and interest groups about that expectation. But the recognition that there is much about the demographic, economic, and energy profile of the 1980's that could not easily have been anticipated in the 1930's and 1940's ought to give us pause about the robustness of projections 40 to 50 years hence. Today's developments in computers, communications, and even the pervasive consequences of automotive growth could not have been credibly assumed 40 to 50 years ago, let alone spun out in their quantitative implications.

As late as 1947, Census Bureau demographers—reeling from what they perceived to be a chronic continuation of the low depression birth rate—projected a year 2000 population of 164 million, a level reached in 1955.

We should remind ourselves that the findings reported here are not predictions but rather a set of outcomes conditioned by assumptions about changes in policy and economic variables, dependent on the accuracy of a host of technical parameters, and governed, in general, by a great deal of uncertainty regarding technological processes and structural change. For example, knowledge about the effects of rising energy prices, which virtually all long-range analysis assume, are severely handicapped by inadequate historical experience and the resultant absence of a suitable data base.

Analysis and projections of energy demand, supply, and price underscore as well the importance of recognizing the virtues, but also the limitations, and indeterminacy resulting from what in economic terminology is called partial equilibrium analysis. We know, of course, that in a dynamic and complex economic system, everything is related to everything else, with the ultimate consequences of a perturbation often incapable of being perceived in the abstract, much less susceptible to believable quantitative estimation. And so, we confine ourselves to a very restricted mode of analysis, asking, for example, how rising income and rising energy prices might affect energy demand on the assumption—known to be unrealistic but necessary for the sake of tractability—that other things hold constant.

In that light, part of our apparent miscalculations for the year 2000 and beyond may not be rectified with the belated appreciation of the role of price in restraining demand. Those very increases in price seem to have concurrently provided the global supply stimulus and eroded OPEC's bargaining strength such that prices may now be softening to the point of reviving an intensification of energy use.

Whether that throws into doubt projections of energy consumption as low as 90 quads in the year 2000, I have no way of knowing. But I would emphasize demand/supply interactions and the indeterminancy factor as grounds for interpreting the significance of such numbers with a certain amount of caution.

The current climate may be as appropriate a context as any to compel such a sorting out process. One of the lessons of the past decade and one of the things to guard against in our thinking about the years ahead is the inclination to compress all that is meaningful in historical insight around upheavals of the last 6 or 12 months and to contemplate future probabilities and possibilities on that restricted base of experience. And so, the Arab oil embargo of 1973–74, the associated quadrupling of world oil prices, and further 1979–80 price escalation accompanying the Iranian revolution each have, in one or another view, constituted the milestone around which the future outlook would inevitably have to be tied. Thus, few analyses in the late seventies contemplated anything but an inevitable upward path in real oil prices; and few doubted that the further level to which the turmoil in Iran was pushing those prices signified an approaching break-even point falling at least within the estimated range of synfuel costs.

This tendency to let the most recent events serve as the ratchet for expectations about things to come isn't limited to events judged to be disasterous, unfavorable, or economically burdensome in their long-term implications. Looking at trends in energy conservation, divisiveness within OPEC, and the break in the world oil price, a Wall Street Journal writer, noting that by "almost any measure, 1982 was a watershed year for energy," recently pronounced that these developments "forever changed the global energy outlook."

A look at the longer sweep of history might produce a somewhat more measured observation: That one moment's well-informed judgment can be dashed in the next moment by marketplace realities.

The second broad question which I wished to touch on is the bearing that real or perceived energy market changes of a basic kind are likely—or ought—to have on long-term R&D decisions. That question is, of course, central to this hearing; but it is also a difficult issue to come to grips with. If private sector decisions were deemed optimal and accorded excusive weight, there would be no problem, or at least none that could be improved upon: a move, say, to withdraw from significant synfuels development could be taken as the strategy appropriate in the light of corporate expectations about energy prices, an assessment of the risks of betting against those expectations, alternative opportunities for the commitment of capital resources, and still other considerations.

For reasons that do not need to be recounted here, long-term R&D needs are, of course, viewed as a shared responsibility of Government and industry. Thus, public officials are compelled to enter the debate about the long-term implications of recent energy trends and market conditions.

Without presuming to prescribe new departures or redirections in Federal policy occasioned by the new developments and projections, let me only mention three points that deserve an airing in this connection:

First, to the extent that we can be more confident today than we could afford to be 5 years ago that a severe demand/supply pinch and steeply higher oil and gas prices would not materialize within the next 10 years or so, policies which at one time aimed for ambitious synfuel production targets in a short period of time might be rethought in favor of different objectives over a different time scale. The uncertainty surrounding a given planning goal has, of course, not disappeared, but may have been shifted forward into the future.

Moreover, we now have a better feel of what is appropriate for which contingencies and this helps put synfuels and other R&D objectives into a more finely differentiated perspective.

Second, in spite of lowered energy consumption projections, divisiveness within OPEC, and greater supply diversity, there is no room to suppose that, over the long term, concentrated dependence on possibly limited Persian Gulf oil supplies will not reappear. This is not an argument for resurrecting notions of energy independence; but it underscores the desirability of an energy R&D strategy based on some degree of risk aversion.

And, finally, it goes without saying that we value secure and economical energy because of its contribution to broader social goals. Energy policy—in all of its forms—is designed to serve that end. This means that we cannot look at the R&D component of that policy in isolation from other measures directed to the same objective; and, within the R&D component, we cannot overlook the way in which various candidates for Federal support—be they conservation, nuclear, synfuels, renewables—promise to conform to the tests of cost effectiveness that, increasingly, are applied to Government policy initiatives.

[The prepared statement of Mr. Darmstadter follows:]

TESTIMONY BY JOEL DARMSTADTER

Representatives Lloyd and Fuqua, members of the subcommittees, I appreciate being asked to contribute to your inquiry into the R&D consequences of changing perceptions about the nation's energy future. I should mention at the outset that while my remarks are based on research conducted at Resources for the Future—on whose staff I serve as a senior fellow—I speak only for myself. Resources for the Future, as an institution, takes no position and makes no recommendations on policy issues.

In my testimony, I plan to address two board topics:

(1) How have U.S. energy-consumption projections to the year 2000 and beyond changed in recent years and what are the principal factors accounting for those changes?

(2) What might be some of the implications for public policy and private-sector decisions as a consequence of shifting perceptions about long-term energy conditions?

I will touch only sparingly on specific R&D policy issues for that is a subject which other witnesses at this hearing are more qualified to deal with.

In spite of an energy forecasting record that, as I will show in a moment, has been rather erratic, the unavoidable need to plan today for circumstances twenty, thirty, or forty years ahead forces us to continue projecting energy treads, using the best data and analytical tools at hand and working with a range of judgments and assumptions appropriate to the strategic decisions which have to be made. Scoffing at the fragility of the forecasting record is not helpful—indeed, it is irresponsible—when, say, as a state utility commissioner, on has to give the go-ahead for a power plant construction program designed to meet energy needs in 2000 and beyond; as an environmental planner concerned with the greenhouse effect, one needs to worry about fossil-fuel demand in the twenty-first century; or, as a Congressional or Administration decision-maker, one is compelled to weigh alternative budgetary priorities in energy R&D.

Now, it is worth recalling that during the decade of the 1970s, the art or science—depending on one's view of the matter—of forecasting energy demand approached the dimensions of a national obsession. There were probably two reasons for this development. One was the oil price shock of 1973-74, which, along with its reverberations to other energy sectors, seemed to portend disturbances and discontinuity in the growth and structure of the economy, in technology, and in personal well-being. True, there had been intermittent earlier preoccupation with future energy adequacy and needs. By and large, however, such concerns did not endure: A condition of plentiful supplies a stable or declining real energy prices had been a fact of life for so long that its presumed permanence made long-range energy assessments unnecessary. In the seventies this was no longer true.

The second reason for the proliferation of future-outlook studies in the energy field goes back to an ideological phenomenon. Energy use was becoming a proxy for, on the one hand, the wherewithal for continued economic growth or, on the other, the route toward an ecological disaster. To the "expansionists"—flippantly characterized by some as the "dig we must" school—increased use of energy facilitiated a rise in living standards; to the "limitationists," it simply intensified the growing problems of the environment, safety, and public health.

Of course, these are representations of extremes in the ideological spectrum. On the economic growth side there were some who appreciated that, by exploiting cost-effective conservation opportunities, more sparing energy use would not significantly jeopardize economic growth; while some environmentalists recognized that imaginative policies and careful management could mute the destructive consequences of higher energy production and consumption. (Numerous economists, perceiving the problem not as a matter of ideology but primarily as one of efficiency—enabling market prices to shape energy and environmental adjustments—found it congenial to embrace both of these notions.)

Still, the antithetical postures depicted above are not simply a caricature of positions that came to the fore in the course of the 1970's. Published energy-demand forecasts or "scenarios" diverged conspicuously depending on who made them. For example, a major 1975 study by the Edison Electric Institute (the trade association for investor-owned utilities) foresaw a level of primary energy requirements totaling 167 quads in the year 2000 if reasonable economic expectations were to be fulfilled. By contrast, Amory Lovin—a prominent environmentalist who, in many ways, personified the concern with "limits"—in 1977 argued the reasonableness of a year 2000 target figure of 100 quads or 40 percent lower. Philosophical positions clearly conditioned analysis. (Even so, Lovins' forecast is likely to turn out to be much more accurate.)

As of 1982–83, a good deal of the sound and fury accompanying the debate over energy in the 1970's has subsided. Why? The record of the last decade has helped shape such a toning-down: the oil price shocks, while severly testing the resilience of the economy—indeed, contributing to the severe recession we have been experiencing—also demonstrated our clearcut ability to use energy more efficiently when the cost of failing to do so was seen to be exceedingly burdensome. There has been a healthy process of demystification about energy: when the stakes are high, other productive resources and human ingenuity can serve as a partial, but very important, substitute. (Analysis at the Oak Ridge National Laboratory suggests that while depressed income has accounted for a substantial portion of the reduction in U.S. energy demand below levels suggested by the pre-1973 trend, an almost equal degree of additional demand restraint has been brought about by the sharp rise in energy costs.) Partly as a result of that recognition, there has also been an emerging consensus. Energy-demand forecasts—embodying substantial conservation assumptions—are both far less divergent and much lower than they would have been a decade ago. Texaco's expectation about annual gasoline demand over the next two decades (in excess of a one-third decline) is unlikely to be sharply out of line with the views of analysts from the conservation movement. Objective reality has penetrated the mindset of groups whose views were once very much in contention. The scaling-back of future demand estimates has been especially conspicuous on the part of those leaning toward the "expansionist" part of the spectrum. (The other side's projections were already quite low.)

These points come to life when we see, from three accompanying tables, how successive energy-demand projections for the years 2000 and 2020 have been progressively reduced. Table 1 above U.S. government projections for 2000 prepared at various intervals since the late 1960's. Tables 2 and 3 contain the comparative results of a number of major efforts (undertaken between 1978 and 1982) to model energy demand substantially beyond the turn of the century.[1]

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[1] The studies summarized in Tables 2 and 3 are the following:

ETA/MACRO—an integrated model of energy-economy relations developed by Alan Manne of Stanford University.

LEAP—the Energy Information Administration's (EIA) "Long-Term Energy Analysis Program" model, a highly detailed dynamic representation of energy supply, conversion, and demand.

Continued

TABLE 1.—*U.S. Government energy consumption projections for the year 2000*

Year of projections:	*Quads* [1]
1968	169
1976	163
1978	125
1980	103
1982	92

[1] One quad equals 10^{15} British thermal units and is the calorific equivalent of approximately 500,000 barrels of oil per day.

Sources: The estimates prepared in 1968 and 1976 came from the U.S. Bureau of Mines (prior to the establishment of DOE). Those for 1978 and 1980 were prepared by the Energy Information Administration within DOE. The 1982 figure was cited by "Inside Energy" (Feb. 21, 1983) as the one to be adopted in DOE's forthcoming biennial National Energy Plan (NEPP IV).

TABLE 2.—COMPARATIVE PROJECTIONS OF PRIMARY ENERGY CONSUMPTION, GNP, AND ENERGY/GNP RATIOS, 1981 AND 2020

[Energy consumption in quads, GNP in trillion 1980 dollars, energy/GNP ratios in thousand BTUs per dollar]

	Year prepared	Energy	GNP	Energy/GNP
Model:				
Actual 1981 data		73.8	2.68	27.53
DESOM	1978	258	8.59	30.0
SRI	1978	240	8.59	28.0
Nordhaus	1978	151	8.59	17.6
ETA/MACRO	1979	166	6.66	25.0
CONAES	1979	160	7.06	22.7
Fossil–2	1979	164	7.11	23.1
BNL/DJA	1979	154	7.72	20.0
RFF/SEAS	1980	158	7.01	22.5
IEA/ORAU	1982	138	5.90	23.4
ORNL	1982	127	7.43	17.1
LEAP	1982	143	6.43	22.2

Note: The models, denoted by the above acronyms, are described in a footnote to the accompanying text. DESOM, SRI, and Nordhaus deliberately use identical projected GNP.

Source: Joel Darmstadter, Douglas McDonald, and Michael Coda, "Review of Post-2000 Energy Projections" (Resources for the Future; prepared for Gas Research Institute). (Distributed by National Technical Information Service, Springfield, Va., PB83–173401.)

ORNL—the results of Oak Ridge National Laboratory's (ORNL) National Energy Perspective study, undertaken to guide ORNL in establishing priorities for research and development over the coming years, and based on a blend of trend analysis and specification of a set of planning objectives.

IEA/ORAU—part of a long-term global framework for energy assessment developed by the Institute for Energy Analysis (of Oak Ridge Associated Universities) and designed to study the implications of carbon dioxide accumulation in the atmosphere.

CONAES—analysis by the Demand and Conservation Panel of the National Research Council's Committee on Nuclear and Alternative Energy Systems which combined sectoral demand scenarios with econometric modeling and explored variability in energy use at given GNP levels.

RFF/SEAS—An adaptation by authors at Resources for the Future of a "Strategic Environmental Assessment System," which, among other complex features, utilizes a dynamic input-output forecasting model.

In addition to our review of the projections developed in these detailed studies, it was possible to consult the results of five more aggregative forecasting efforts. Two of these (known as the BLN/DJA and Fossil-2 models) were taken from a DOE comparative assessment which ran several models under a set of common assumptions. The other three (DESOM, SRI, and Nordhaus models) were taken from a similar assessment done for the CONAES. The DOE assessment appears in Andy S. Kydes and John D. Pierson, "A Comparative Assessment of Five Long-Run Energy Projections," Report to the Energy Information Administration, U.S. Department of Energy, 1979. The CONAES assessment appears in National Academy of Sciences, "Energy Modeling for an Uncertain Future," Report of the Modeling Group Synthesis Panel of the Committee on Nuclear and Althernative Energy Systems, Supporting Paper No. 2, 1978.

The acronyms cited in the text above are defined as follows: BNL/DJA-Brookhaven National Laboratory/Dale Jorgenson Associates, DESOM-Dynamic Energy System Optimization Model, and SRI-Stanford Research. "Nordhaus" refers to Prof. William Nordhaus of Yale University, and "Fossil-2" refers to a systems dynamics simulation model designed to evaluate the potential magnitude of the U.S. energy problem and to assess the impact of various policy options on the U.S. energy system.

TABLE 3.—COMPARATIVE PROJECTED AVERAGE ANNUAL PERCENTAGE CHANGE IN PRIMARY ENERGY CONSUMPTION, GNP, AND ENERGY/GNP RATIO, 1981–2020

	Year prepared	Energy	GNP	Energy/GNP
Model:				
DESOM	1978	3.3	3.0	0.2
SRI	1978	3.1	3.9	0.0
Nordhaus	1978	1.9	3.0	−1.1
ETA/MACRO	1979	2.2	2.4	−0.2
CONAES	1979	2.0	2.5	−0.5
Fossil-2	1979	2.1	2.5	−0.4
BNL/DJA	1979	1.9	2.7	−0.8
RFF/SEAS	1980	2.0	2.5	−0.5
IEA/ORAU	1982	1.6	2.0	−0.4
ORNL	1982	1.4	2.6	−1.2
LEAP	1982	1.7	2.3	−0.6

Note: All rates of change are calculated using the authors' absolute levels for 2020 (or our estimates thereof) and actual figures for 1981. Thus, the rates of change shown may differ from rates shown in the different models, based on other base years.

A less bullish long-term economic prognosis is one of the explanation for those steadily reduced estimates. But the demonstrated potential for, and assumed further exploitation of, energy efficiency opportunities is an equally, if not more, important reason. Between 1973 and 1981, the energy/GNP ratio fell at an average rate of nearly 2½ percent annually. So it is not unexpected that the most recent long-term-forecasts, recognizing the adjustment under way in response to rising real energy prices, assume that continued—if decelerating—declines in the energy/GNP ratio will continue under the impact of the persistent price pressures embodied in the forecasts.

Table 3, which translates the absolutes of Table 2 into average annual rates of change, points up this change of expectations succinctly. The most recent studies reviewed, taken together, suggest long-term energy growth averaging around 1.6 percent yearly, GNP growth of approximately 2.5 percent, and an energy/GNP ratio declining by a rate of 1.1 percent. Of course, a perpetually declining energy/GNP ratio defies both economic logic and physicial reality, for it suggests, on the one hand, that energy is becoming a steadily less desirable economic good, and on the other, that the nation is capable of supporting a given level of GNP by using an amount of energy approaching zero! But even at this writing, newly released studies—e.g., at Resources for the Future and the Gas Research Institute—suggest that we haven't seen the last of the observed tendency for successive analyses to scale back estimated energy consumption levels and energy/GNP rations. Thus, in its most recent scaling back, GRI's October 1982 "Baseline" case to 2000 shows primary energy consumption of 1.4 percent yearly, reaching a level of 96.4 quads in that year. (The associated GNP growth rate is 2.6 percent; the energy/GNP ratio faills by 1.9 percent.) If, as suggested by Table 2, a stylized projection for the year 2020 hovers around 135 quads, to reach that level would require a 1.7 percent growth rate from the GRI 2000 level. As noted above, energy growth, significantly trailing GNP growth in perpetuity doesn't seem in the cards, so that the possibility of some eventual step-up in the energy growth rate cannot be dismissed. But it is hard to imagine such a turning point less than two decades away. What this suggests is that 135 quads is very likely near to an upper limit to the level of demand in 2020, while a mid-range spread of, say, 115–125 quads appears to be a much more reasonable extension of the most recent thinking by GRI and others.

To summarize to this point: there has been a drastic scaling-down of projected level of energy consumption 20 and 40 years hence; and there appears to be diminishing divergence among different analysts and interest groups about that expectation. But, the recognition that there is much about the demographic, economic and energy profile of the 1980's that could not easily have been anticipated in the 1930's and 1940's ought to give us pause about the robustness of projections 40–50 years hence. Today's developments in computers, communications, and even the pervasive consequences of automotive growth could not have been credibly assumed 40–50 years ago, let alone spun out in their quantitative implications. As late as 1947, Census Bureau demographers—reeling from what they perceived to be a chronic continuation of the low depression birth rate—projected a year 2000 population of 164 million, a level reached in 1955!

In this connection, we should remind ourselves that the findings reported here are not predictions but rather a set of outcomes conditioned by assumptions about changes in policy and economic variables, dependent on the accuracy of a host of technical parameters, and governed, in general, by a great deal of uncertainty regarding technological processes and structural change. For example, knowledge about the effects of rising energy prices, which virtually all long-range analyses assume, are severely handicapped by inadequate historical experience and the resultant absence of a suitable data base.

Analysis and projections of energy demand, supply, and price underscore as well the importance of recognizing the virtues, but also the limitations, and indeterminacy resulting from what in economic terminology is called "partial equilibrium" analysis. We know, of course, that in a dynamic and complex economic system, everything is related to everything else, with the ultimate consequences of a perturbation often incapable of being perceived in the abstract, much less susceptible to believable quantitative estimation. And so, we confine ourselves to a very restricted mode of analysis, asking, for example, how rising income and rising energy prices might affect energy demand on the assumption unrealistic but necessary for the sake of tractability—that other things hold constant. In that light, part of our apparent miscalculations for the year 2000 and beyond may not be rectified with the belated appreciation of the role of price in restraining demand. Those very increases in price seem to have concurrently provided the global supply stimulus and eroded OPEC's bargaining strength such that prices may no be softening to the point of reviving an intensification of energy use. Whether that throws into doubt projections of U.S. energy consumption as low as 90 quads in the year 2000, I have no way of knowing. But I would emphasize demand-supply interactions and the indeterminacy-factor as grounds for interpreting the significance of such numbers with a certain amount of caution.

I should acknowledge that one of the models reported on in Tables 2 and 3—namely the ETA/MACRO effort—does adopt a "general" rather than a partial equilibrium approach. This model, requiring for its solution mutually interactive adjustment on the demand and supply sides, has conceptual elegance, but—inevitably—is forced to be so heroic in the many variables and relationships that must be quantified irrespective of empirical justification, that the importance of its contribution is probably more methodological than in its substantive findings. For example, in such a model, the penetration of synfuels and—more broadly—of "backstop" technologies tends to be treated in too disembodied a fashion, the appearance of such alternative energy systems and sources being tightly governed by relative supply prices and other variables and parameters. Yet, observing the chronically roller-coaster behavior of synfuel projects, one wonders whether such technological characteristics of a future energy system might not, after all, be treated more effectively "outside," or as on adjunct to, a formal model. Thus, I flag as a problem the need to deal with, or at least to recognize, the problem of demand-supply interactions, but I cannot report that our present command of the problem is secure.

All these caveats aside, projections for the next 20-40 years are, as I noted earlier, increasingly demanded. Some comfort can be derived from the reasonable degree of consensus surrounding numerous indicators which were projected in the different studies reviewed. At the same time, both producers and users of long-term projections have a responsibility for continual monitoring of such new data, new analytical tools and significant departures in demographic, economic and energy developments as to compel a re-assessment of the long-range trends previously charted. In this respect, the ability to differentiate fundamental, as distinct from ephemeral, change in conditions is no small part of the task that must be faced up to.

The current climate may be as appropriate a context as any to compel such a sorting-out process. One of the lessons of the past decade and one of the things to guard against in our thinking about the years ahead is the inclination to compress all that is meaningful in historical insight around upheavals of the last 6 or 12 months and to contemplate future probabilities and possibilities on that restricted base of experience. And so, the Arab oil embargo of 1973-74, the associated quadrupling of world oil prices, and the further (1979-80) price escalation accompanying the Iranian revolution each have, in one or another view, constituted the milestone around which the future outlook would inevitably have to be tied. Thus, few analyses in the late seventies contemplated anything but an inevitable upward path in real oil prices; and few doubted that the further level to which the turmoil in Iran was pushing those prices signified an approaching break-even point falling at least within the estimated range of synfuel costs. This tendency to let the most recent events serve as the ratchet for expectations about things to come isn't limited to events judged to be disastrous, unfavorable, or economically burdensome in their long-term implications. Looking at trends in energy conservation, divisiveness within OPEC, and the break in the world oil price, a Wall Street Journal writer, noting that by "almost any measure, 1982 was a watershed year for energy," recently pronounced that these developments "forever changed the global energy outlook." (Youssef M. Ibrahim, Wall Street Journal, June 9, 1983) A look at the longer sweep of history might produce a somewhat more measured observation: that one moment's well-informed judgment can be dashed in the next moment by marketplace realities.

The second broad question which I wished to touch on is the bearing that real or perceived energy-market changes of a basic kind are likely—or ought—to have on long-term R&D decisions. That question is, of course, central to this hearing; but it is also a difficult issue to come to grips with. If private-sector decisions were deemed optimal and accorded exclusive weight, there'd be no problem, or at least none that could be improved upon: a move, say, to withdraw from significant synfuels development could be taken as the strategy appropriate in the light of corporate expectations about energy prices, an assessment of the risks of betting against those expectations, alternative opportunities for the commitment of capital resources, and still other considerations. For reasons that do not need to be recounted here, long-term R&D needs are, of course, viewed as a shared responsibility of government and industry. Thus, public officials are compelled to enter the debate about the long-term implications of recent energy trends and market conditions.

Without presuming to prescribe new departures or re-directions in Federal police occasioned by the new developments and projections, let me only mention three points that deserve an airing in this connection:

(1) To the extent that we can be more confident today than we could afford to be five years ago that a severe demand-supply pinch and steeply higher oil (and gas) prices would not materialize within the next 10 years or so, policies which at one time aimed for ambitious synfuel production targets in a short period of time might be re-thought in favor of different objectives over a different time scale. The uncertainty surrounding a given planning goal has, of course, not disappeared, but it may now bracket a considerably scaled-down range of projected estimates. Moreover, we now have a more discriminating sense of which different policy instruments—including, for example, the SPR—are appropriate for which contingencies; and this helps put synfuels and other R&D objectives into a more finely differentiated perspective.

(2) In spite of lowered energy consumption projections, divisiveness within OPEC, and greater supply diversity, there is no reason to suppose that, over the long term, concentrated dependence on possibly limited Persian Gulf oil supplies will not reappear. This is not an argument for resurrecting notions of energy independence; but it underscores the desirability of an energy R&D strategy based on some degree of risk aversion.

(3) It goes without saying that we value secure and economical energy because of its contribution to broader social goals. Energy policy—in all of its forms—is designed to serve that end. This means that we cannot look at the R&D component of that policy in isolation from other measures directed to the same objective; and, within the R&D component, we cannot overlook the way in which various candidates for Federal support—be they conservation, nuclear, synfuels, renewables—promise to conform to the tests of cost-effectiveness that, increasingly, are applied to government policy initiatives.

Mr. FUQUA. Thank you very much.

[The biographical sketch of Dr. Dreyfus follows:]

BIOGRAPHICAL INFORMATION

Daniel A. Dreyfus

Dr. Dreyfus was born in Brooklyn, New York, March 5, 1931. He attended public schools in a number of states and graduated from the Meguro High School in Tokyo, Japan.

He attended the Technological Institution of the Northwestern University, received the degrees of Bachelor of Civil Engineering and Master of Engineering Administration from the George Washington University, and the degree of Doctor of Philosophy from the American University.

Since receipt of his Bachelor's degree, Dr. Dreyfus has been employed as a refinery construction engineer for Texaco, a remote-site planning engineer for the Alaska District of the U.S. Army Corps of Engineers, and in various budget and planning positions with the Bureau of Reclamation of the Department of the Interior.

In 1968, he joined the Professional Staff of the Senate Committee on Interior and Insular Affairs, initially as the staff member for the Subcommittee on Water and Power Resources. In January of 1975, he became the Deputy Staff Director of the Committee which, in the Senate reorganization of January 1977, became the Committee on Energy and Natural Resources. The Committee's jurisdiction encompasses all of the energy programs of the Department of Energy and the natural resource programs of the Department of the Interior.

In January of 1979, Dr. Dreyfus became the Staff Director of the Committee; and in January of 1981, upon Republican assumption of leadership in the Senate, he became Staff Director for the Minority of the Committee. During his Senate service, he was also Engineering Consultant for the Senate Fuels and Energy Policy Study which included participation by several committees.

Since leaving the government service in June of 1981, Dr. Dreyfus has become the Director of Strategic Analysis and Energy Forecasting for the Gas Research Institute (GRI). GRI is a non-profit organization which plans and manages a comprehensive research and development program on behalf of the natural gas industry.

After enlisted infantry service in Korea, Dr. Dreyfus was commissioned in the Corps of Engineers, U.S. Army Reserve. He is a member of the American Society of Civil Engineers, the Society of American Military Engineers, the Society of Professional Engineers, the American Political Science Association, and the American Society for Public Administration.

He is married, has five children, and is a resident of McLean, Virginia.

Mr. **Fuqua**. Dan, we are happy to welcome you. I hope it doesn't feel too strange sitting on that side of the table there.

Dr. **Dreyfus**. Thank you, Mr. Chairman.

I have spent a good many hours on this side of the table in House hearing rooms and I feel a lot more comfortable today than I did then.

Mr. **Fuqua**. I might point out to the members that Dr. Dreyfus was the Staff Director of the Senate Energy Committee for many years and did a very outstanding job and we worked together on many, many projects and many bills and authorizations and reorganizations, et cetera.

Glad to have you, Dan.

STATEMENT OF DR. DANIEL A. DREYFUS, DIVISION DIRECTOR, STRATEGIC ANALYSIS AND ENERGY FORECASTING, GAS RESEARCH INSTITUTE

Dr. **Dreyfus**. Thank you.

I am pleased to have an opportunity to appear before you today to discuss GRI's use of models in strategic planning and the implications of the expectation of lower oil prices for gas research and development. You have my prepared statement and attachments and I will briefly summarize the highlights.

GRI is an independent, not-for-profit scientific research organization created by the gas industry in 1976 to plan, finance, and manage an expanded and fully coordinated gas-related research and development program for the mutual benefit of the regulated gas industry and its ratepayers. In compliance with stipulated procedures, GRI submits its annual plan and 5-year R&D program to the Federal Energy Regulatory Commission for review and approval.

In order to plan its R&D program, GRI develops an institutional view of the long-range future of the gas industry. To be sure the results of the R&D program address the future needs of the industry and its consumers, GRI must project the environment within which the products of its R&D program will have their application.

The GRI program includes both short- and long-range R&D projects. The FERC review of the program imposes a requirement that GRI evaluate its R&D projects by means of objective, quantitative cost-benefit analyses. These two factors create a need for a general baseline projection of U.S. energy supply and demand to the year 2000 with a significant level of background detail on projected energy quantities and prices to facilitate economic assessment of potential technologies.

These criteria, in turn, dictate the use of relatively complex analytical tools or models in developing the baseline projection. GRI uses complex modeling techniques, therefore, not with any belief that model complexity enhances the validity of long-range forecasts. Rather, we use them because they impose discipline and rigor upon the forecasting activity; and they provide a convenient and economical means of generating the wealth of background detail, consistent with the general projection, which we require for internal technology asessment and program planning analyses.

I would like to make some general observations about the use of models as predictive tools. To some extent, I will repeat what has been said before.

Fundamentally, a model is no more than an accounting system. Complex models help to keep track of the numerous interrelationships among variables which have been observed historically or which are intuitively expected to occur in the future. Complex models of the economic system or of interacting energy supply and demand relationships provide a means by which a number of analysts can combine their efforts at understanding the observed data and create a single integrated calculation.

The user of such a complex model can either accept the results of the model builders' collective judgments or he can modify the model to conform to his own judgments.

The complex model, therefore, offers a decisionmaker several advantages over purely intuitive projections.

It incorporates the results of a great deal of effort to understand and mathematically describe multiple relationships among multiple factors, usually based upon actual historical experience.

As Mr. Evered pointed out, it imposes a discipline upon the intuitive thought process. If the model user postulates a set of assumptions which are inconsistent in terms of past experience, it is likely that the model will call this to his attention.

Complex models, however, also have several inescapable limitations.

All such models are a combination of descriptions of historically observed relationships and judgments by the model makers. They are good at predicting the future under stable conditions, but they have no special ability to predict future discontinuities in trends—such as those which resulted from the Arab oil embargo, or the political instabilities mentioned previously by the chairman.

Econometric models, especially, rely on historical correlations. If some variable, for example the oil price, changes dramatically from historical experience, these correlations are unlikely to continue to prevail.

Process or engineering type models are somewhat more useful for dealing with discontinuity. They better reflect the capabiity of physical systems to accommodate change. But predicting that some level of change such as an extreme measure of energy conservation or solar applications, is physically possible sheds very little light on how much actually will take place.

All models, no matter how complex, moreover, are gross simplifications of the real world. They include the model markers' judgments of which factors are sufficiently consequential to be included. These judgments, again, are based upon historical observation and do not necessarily apply in the future. Imports, for example, were not a significant determinant for predicting U.S. auto industry sales in the 1950's. Certainly they are today.

In summary, complex models predict the continuation of historical trends quite well. But discontinuities in trends, which often are the most important aspects of the future for planning decisions, are basically a matter of intuition and insights. Models can discipline and assist intuitive forecasting, but they cannot replace it.

I have included as an attachment to my statement a description of GRI's process for the development of its projection. I will not go into that here because it is available to the committee.

Prior to the reduction in world oil prices which occurred at the beginning of 1983, a prevailing expectation of future oil price escalation drove up much of Government and industry decisionmaking. Most people had concluded that the one certainty in the energy future was that oil prices would continue to increase more rapidly than general inflation. Furthermore, most expected that one or more major increases or price shocks were inevitable within the next two decades.

A great many investments were made by Government and industry based on this supposed economic certainty. These decisions were reflected, among other things, in real and proposed initiatives in coal conversion of existing facilities, expansion of the infrastructure for the global waterborne coal and LNG trades, and ambitious synthetic fuels programs.

Since the recent price reduction, the new conventional expectation of stable or even decreasing world oil prices has called most of these decisions into question. Already the global coal and LNG supply infrastructure capacities exceed demand, new coal conversion investments have virtually ceased, and the priority assigned to developing new technologies to back out oil has definitely diminished.

The expectation of low future oil prices affects the gas industry on both the supply and demand side of the forecast equation.

The current debate over the outlook for natural gas prices has concentrated on the probable market clearing price which would permit gas to retain its competitive position, especially in the industrial market. Much less consideration has been given to the supply side of the price issue. However, the economic future of the gas industry and its customers is equally dependent upon assurances of adequate gas supplies at competitive prices.

With regard to end use energy demand sectors, the models tell us that lower oil prices will definitely shift the U.S. energy mix to greater dependence on petroleum products. For our 1982 baseline projection, we had assumed average world oil prices would reach $48 in the year 2000 in current dollar terms. This implied about a 2 pecent annual increase above inflation over the long term. For the model runs we are now making for our 1983 projection and reflecting the recent decrease, we still assume a 2 percent long-term increase in oil prices, but the increase starts from a lower base year and results in a price of $40 in the year 2000.

As a result of this change in oil price assumptions, the total increase in petroleum demand in the U.S. is about 2 quads in the year 2000, or about 1 million barrels per day more of consumption.

Because domestic oil production throughout the projection period falls short of demand, this increase would be met entirely with a net increase in oil imports.

Based upon our hydrocarbon model supply studies and other work, however, we believe that gas can continue to hold its market share against the lower oil prices if the transition toward greater deregulation of wellhead prices permits rational market-based decisions to be made. In the industrial and electric utility sectors, gas competes directly with No. 6, or residual fuel oil, its lowest priced petroleum competitor. Given 1 year's time for minor equipment modifications, about five quads of current industrial gas demand in these sectors, or about 25 percent of total gas demand, could switch to resid.

We do not expect this to happen. We believe that gas prices which are competitive with residual fuel oil at the burner tip can sustain gas production at levels adequate to maintain gas markets equal to or greater than the present level of demand. This, of course, will occur only if the rational pricing does take place.

Oil prices, of course, also have implications for R&D strategy in the gas industry. In the current circumstances of oversupply and increasing prices along with restricted budgets coming out of market losses, GRI has assigned priority to those programs that can reduce the cost of the energy services to its rate payers in the shorter run and has had to defer or reduce R&D in longer term, supplemental technologies.

GRI's proposed program for 1984 will concentrate 54 percent of total R&D budget on efficient utilization technologies which have a high potential for reducing costs to residential customers and keeping gas competitive with other energy forms in commercial and industrial applications.

A strong program also is continued and unconventional gas technologies which have an opportunity of reducing gas prices across the board in the near term.

Despite the current idle production capacity for oil in the world, it seems inevitable that world oil prices eventually will regain the escalation trend in excess of general inflation. Oil has superior physical properties which make it a preferred energy source for many applications. It is particularly suited to transportation uses and there is a massive pent-up demand for transportation services throughout the world and especially in the Third World.

Furthermore, it remains uncertain what portion of the current reduction in world energy demand has resulted from real efficiencies and permanent social changes and how much is the temporary effect of an extended global recession. With worldwide economic recovery and an acceptable level of economic growth in the lesser developed countries, pressure will again eventually be placed on world petroleum capacity. Producing nations will regain the ability to apply a pricing strategy.

There is still strong justification for the U.S. Government to encourage reduction of dependence upon imported oil for energy. Natural gas should play an important role in any U.S. strategy for energy management. Gas is a large domestic resource. Compared to many other energy sources, it is environmentally benign. It can be prouced at costs comparable with any suitable alternative, and the installed infrastructure of transportation, storage and delivery systems is an invaluable national asset.

Technically, the share of national energy needs born by gas could be greater. With an aggressive R&D effort, gas can continue to carry a major portion of U.S. energy demand well beyond the end of this century.

That completes my statement.

[The prepared statement of Dr. Dreyfus follows:]

TESTIMONY BY DR. DANIEL A. DREYFUS, DIVISION DIRECTOR, STRATEGIC ANALYSIS AND ENERGY FORECASTING, GAS RESEARCH INSTITUTE

I am Daniel Dreyfus, Division Director for Strategic Analysis and Energy Forecasting of the Gas Research Institute (GRI). I am pleased to have the opportunity to appear before you today to discuss GRI's use of models in strategic planning and the implications of the expectation of lower oil prices upon research and development funding.

GRI is an independent, not-for-profit scientific research organization created by the gas industry in 1976 to plan, finance, and manage an expanded and fully coordinated gas-related research and development program for the mutual benefit of the regulated gas industry and its ratepayers. In compliance with stipulated procedures, GRI submits its annual plan and five-year R&D program to the Federal Energy Regulatory Commission for review and approval.

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These criteria, in turn, dictate the use of relatively complex analytical tools or models in developing the baseline projection. GRI uses complex modeling techniques, therefore, not with any belief that model complexity enhances the validity of long-range forecasts. Rather, we use them because they impose discipline and rigor upon the forecasting activity; and they provide a convenient and economical means of generating the wealth of background detail, consistent with the general projection, which we require for internal technology assessment and program planning analyses.

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As Mr. Evered pointed out, it imposes a discipline upon the intuitive thought process. If the model user postulates a set of assumptions which are inconsistent in terms of past experience, it is likely that the model will call this to his attention.

Complex models, however, also have several inescapable limitations.

All such models are a combination of descriptions of historially observed relationships and judgments by the modelmakers. They are good at predicting the future under stable conditions, but they have no special ability to predict future discontinuities in trends (such as those which resulted from the Arab oil embargo).

Econometric models, especially, rely on historical correlations. If some variable (for example, the oil price) changes dramatically from historical experience, these correlations are unlikely to continue to prevail.

Process or engineering type models are somewhat more useful for dealing with discontinuity. They better reflect the capability of physical systems to accommodate change. But predicting that some level of change (such as an extreme measure of energy conservation or solar applications) is physically possible sheds very little light on how much actually will take place.

All models, no matter how complex, moreover, are gross simplifications of the real world. They include the modelmakers' judgments of which factors are sufficiently consequential to be included. These judgments, again, are based upon historical observation and do not necessarily apply in the future. Imports, for example, were not a significant determinant for predicting U.S. auto industry sales in the 1950s. Certainly they are today.

In summary, complex models predict the continuation of historical trends quite well. But discontinuities in trends, which often are the most important aspects of the future for planning decisions, are basically a matter of intuition and insights. Models can discipline and assist intuitive forecasting, but they cannot replace it.

A great many investments were made by government and industry based on this supposed economic certainty. These decisions were reflected, among other things, in real and proposed initiatives in coal conversion of existing facilities, expansion of the infrastructure for the global water-borne coal and LNG trades, and ambitious synthetic fuels programs.

Since the recent price reduction, the new conventional expectation of stable or even decreasing world oil prices has called most of these decisions into question. Already the global coal and LNG supply infrastructure capacities exceed demand, new coal conversion investments have virtually ceased, and the priority assigned to developing new technologies to back out oil has definitely diminished.

The expectation of low future oil prices affects the gas industry on both the supply and demand sides of the forecast equation.

The current debate over the outlook for natural gas prices has concentrated on the probable "market clearing" price which would permit gas to retain its competitive position, especially in the industrial market. Much less consideration has been given to the supply side of the price issue. However, the economic future of the gas industry and its customers is equally dependent upon assurances of adequate gas supplies at competitive prices.

Based upon our hydrocarbon model supply studies and other work, however, we believe that gas can continue to hold its market share against the lower oil prices if the transition toward greater deregulation of wellhead prices permits rational market-based decisions to be made. In the industrial and electric utility sectors, gas competes directly with Number 6, or residual fuel oil, its lowest priced petroleum competitor. Given a year's time for minor equipment modifications, about five quads of current industrial gas demand in these sectors, or about 25 percent of total gas demand, could switch to resid.

We do not expect that to happen. We believe that gas prices which are competitive with residual fuel oil at the burner tip can sustain gas production at levels adequate to maintain gas markets equal to or greater than the present level of demand.

Furthermore, it remains uncertain what portion of the current reduction in world energy demand has resulted from real efficiencies and permanent social changes and how much is the temporary effect of an extended global recession. With worldwide economic recovery and an acceptable level of economic growth in the lesser developed countries, pressure will again eventually be placed on world petroleum capacity. Producing nations will regain the ability to apply a pricing strategy.

There is still strong justification for the United States government to encourage reduction of dependence upon imported oil for energy. Natural gas should play an important role in U.S. strategy for energy management. Gas is a large domestic resource. Compared to many other energy sources it is environmentally benign. It can be produced at costs comparable with any suitable alternative, and the installed infrastructure of transportation, storage and delivery systems is an invaluable national asset.

In 1982 gas consumption stood at 18.4 quads, 26 percent of total U.S. energy consumption.

Technically, the share could be greater. With an aggressive R&D effort, gas can continue to carry a major portion of U.S. energy demand well beyond the end of this century.

PROJECTION HYDROCARBON PRODUCTION AND COSTS: AN INTEGRATED APPROACH

Thomas J. Woods[1]
and
E. Harry Vidas[2]

Abstract

A model to project trends in U.S. oil and natural gas production and costs within the context of an integrated hydrocarbon model has been developed by the Gas Research Institute and Energy and Environmental Analysis, Inc. This model treats the exploration for oil and natural gas as two aspects of the same exploration process. The directionality of the exploration process is captured via a detailed description of the hydrocarbon resource base by type (oil and gas), location, field size, and depth.

[1] Gas Research Institute, 1019 19th Street, N.W., Suite 615, Washington, D.C. 20036

[2] Energy and Environmental Analysis, Inc., 1111 North 19th Street, Arlington, VA 22209

Projecting Hydrocarbon Production and Costs: An Integrated Approach

In attempting to understand the trends in natural gas production and costs, it is important to realize that one explores for and finds hydrocarbons, not oil or gas. The apparent directionality observed in hydrocarbon exploration is a reflection of drilling location (i.e., region and depth), not prescience on the part of the explorer about whether a particular prospect contains oil or gas. As a result, the trends in natural gas production and costs must be viewed within the perspective of overall hydrocarbon production and trends. It should be noted that the same prescription applies to oil production and costs as well.

To capture the linkage between oil and gas in exploration and production activity, GRI has developed a Hydrocarbon Model to provide a capability to project natural gas production and cost trends. The purpose of the GRI Hydrocarbon Model is to provide a rigorous and consistent framework for analyzing the resource cost of finding, developing, and producing natural gas and crude oil in the lower-48 United States. The important features which distinguish the GRI modeling approach from other oil and gas supply models include:

- Extensive use of detailed field and drilling data bases.

- High degree of disaggregation in the characterization of the potential resource base.

- Realistic modeling of industry decision-making techniques to determine the level, location, and directionality (i.e., oil vs. gas) of drilling activity over time.

The initial development of the Hydrocarbon Model has been completed. This paper outlines the basic structure of the model and presents the results of some test runs with the model. The paper will also briefly describe future development work planned for the model in 1983.

Model Structure

The Hydrocarbon Model is based on a highly detailed description of the hydrocarbon resource base. The resource base, both discovered and undiscovered, is described on a field-by-field basis. The individual fields are characterized by type (e.g., oil, gas, oil and gas), size (20 sizes ranging from 4,400 barrels of oil equivalent (BOE) to 2.3 billion BOE), and location. Location is defined both geographically and by depth. There are 10 onshore and 3 offshore geographical regions, patterned after the Potential Gas Committee regions. Onshore, the hydrocarbon resource is divided into the following four depths:

- 0 to 5,000 feet
- 5 to 10,000 feet
- 10 to 15,000 feet
- Below 15,000 feet

The offshore Gulf region is to be divided into three water depths: 0 to 250 feet, 250 to 600 feet, and beyond 600 feet. Currently, however, it only has one depth. The Atlantic and Pacific offshore regions have only one water depth.

In the model, hydrocarbon production and costs are affected by three major factors. They are:

1. The Hydrocarbon Resource Base. This describes the extent of the hydrocarbon resource base at which exploration activity can be directed. As the resource base is depleted, exploration costs will rise.

2. Hydrocarbon Exploration Activity. The exploration activity discovers hydrocarbons, despite driller preferences. Although an area may be highly gas or oil prone, there will still be a likelihood (except at extreme depths) of finding both hydrocarbon types. The exploration costs are proportionally allocated to oil and gas on the basis of what is discovered. Exploration costs are a function of resource depletion, not field size.

3. Hydrocarbon Development Activity. This activity is directional because, once the field is discovered and defined, development drilling is targeted at oil or gas. Any costs involved in development activity are specifically apportioned to oil or gas. Development costs are a function of field size, not resource depletion.

The GRI Hydrocarbon Model has been designed to operate in two modes: as a time-dimensionless curve generator and as a simulator of drilling activity over time. The first mode is used to show how the oil and gas resource base is distributed with regard to the cost of discovery, development, and producton. In this mode a cost/quantity curve is created showing the amount of gas that eventually would be found and produced given a certain price. Such curves cannot be used as a basis to develop an annual production/reserve addition trend. They only serve to indicate the extent to which the hydrocarbon fields in place can be developed at a specified price.

Specific annual rates of production and reserve additions are generated in the second mode. In this mode the model simulates drilling decisions during each model period - generally a five-year interval. The model chooses the level and location of exploratory drilling in new fields in each model period. Within the model, this exploratory drilling then leads to the discovery of new fields and, over time, to reserve additions, development drilling, and production. The timing of reserve additions, development drilling, and production following a field's discovery is fixed in the model.

The model can simulate these drilling decisions from two different perspectives: a "producer" perspective and a "gas purchaser" perspective. In the "producer" perspective mode, the Hydrocarbon Model calculates trends in natural gas production and costs based on "producer" expectations of oil and gas selling prices. In the "gas purchaser" perspective mode, the model calculates natural gas production and cost trends which result when purchasers seek to obtain a particular level of natural gas supply under a particular set of producer price expectations.

In either of these modes, the Hydrocarbon Model calculates a hydrocarbon resource cost sufficient to provide a particular real rate of return after taxes (the current runs use 10 percent). The resource cost is based on the assumption that all hydrocarbons proportionally share exploration costs. As a result, gas and oil would be costed at almost the same level. This cost that the model calculates does not necessarily equal the target prices set for the producer's expectations.

Model Dynamics

The operations of the Hydrocarbon Model are governed by two principal factors:

- The exploration and development process.

- Financial considerations.

1. Exploration and Development Process

The key feature of any exploration and development model is its representation of how exploratory activity leads to the discovery of additional reserves. This discovery process is usually modeled through "find rate equations." The most commonly used specification for find rate equations (e.g., the Department of Energy's National Oil and Gas Supply Model) relates footage drilled to barrels of oil or Mcf of gas found. Such find rate equations usually are statistically fitted using historical American Petroleum Institute/American Gas Association reserve data along with API/American Association of Petroleum Geologists aggregate drilling statistics.

In developing the discovery process for the GRI Hydrocarbon Model, a major consideration was that the approach be as accurate as possible and that it be able to accurately reflect the cost of finding and developing oil and gas reserves. The major deficiencies found in the conventional footage/reserve find rate equations were:

- The cost per foot for a well rises steeply with the depth of the well. Using footage as the independent variable in the find rate equation would distort drilling costs when deeper wells are drilled as resources at shallower depths are depleted.

- Significant economies of scale exist in developing oil and gas fields, both onshore and especially offshore. Find rate equations that do not specify reserves found by the distribution of field sizes cannot accurately deal with development costs.

- The API/AGA annual reserve addition data are extremely volatile and lead to poor statistical fits, especially on a state or a regional basis.

To overcome these deficiencies, geographic regions were broken out into depth intervals. The distribution of field sizes within each depth interval was modeled using modified Arps-Roberts find rate equations. These equations are used to predict the number of fields of a certain size that will be discovered after a given number of exploratory wells have been drilled. There are separate equations for each size class of field (e.g., size class 10 is between .76 and 1.52 million BOE within each depth interval within each region. The GRI model has 13 regions, up to 4 depth intervals, and 20 field sizes for a total of approximately 1,000 separate find rate equations.

For regions and depth intervals with substantial exploratory histories, these find rate equations are solved using historical data. For relatively unexplored areas where insufficient data exist to fit these equations, the equations are estimated by analogy to mature areas. This is done by taking an estimate of the recoverable resource in an area (e.g., from U.S. Geological Survey or Potential Gas Committee estimates) and distributing it by an assumed field size distribution for the GRI model.

The operation of the find rate equation is shown in Figure 1. A level of exploratory wells is inputted into the equations for a given "area," i.e., a specific region and depth interval, to solve for the number of discovered fields in each size class. The number of wells inputted is the cumulative number of wells actually drilled up to the starting date of the model simulation, say, 5,000 wells. The additional interval of wells, say, 500, can be determined by inputting the value 5,500 into the equations and computing the difference in the cumulative field discoveries between 5,000 and 5,500 wells. The number of fields to be found with yet another 500 wells is found by repeating this procedure with the inputted values of 5,500 and 6,000 wells.

The number of new fields in each size class is then broken down into oil and gas fields based on geologic occurrence (the ratio of gas to oil fields increases with depth as well as varying by region). Based on the expected target prices of oil and gas, the after-tax cash flow to develop and produce each field is determined to see if it meets the required rate of return. If not, that field will not be developed. At higher expected oil and gas prices, smaller fields are economic to develop (see Figure 2). This procedure is repeated for each type and size of field. For those fields which are economic to develop, the results are summed up for number of fields, reserve additions and development cash flows. The cost of drilling the 500 exploratory wells is then added to these results to determine total after-tax cash flow for the drilling increment of 500 exploratory wells.

Figure 1

Operation of Find-Rate Equations

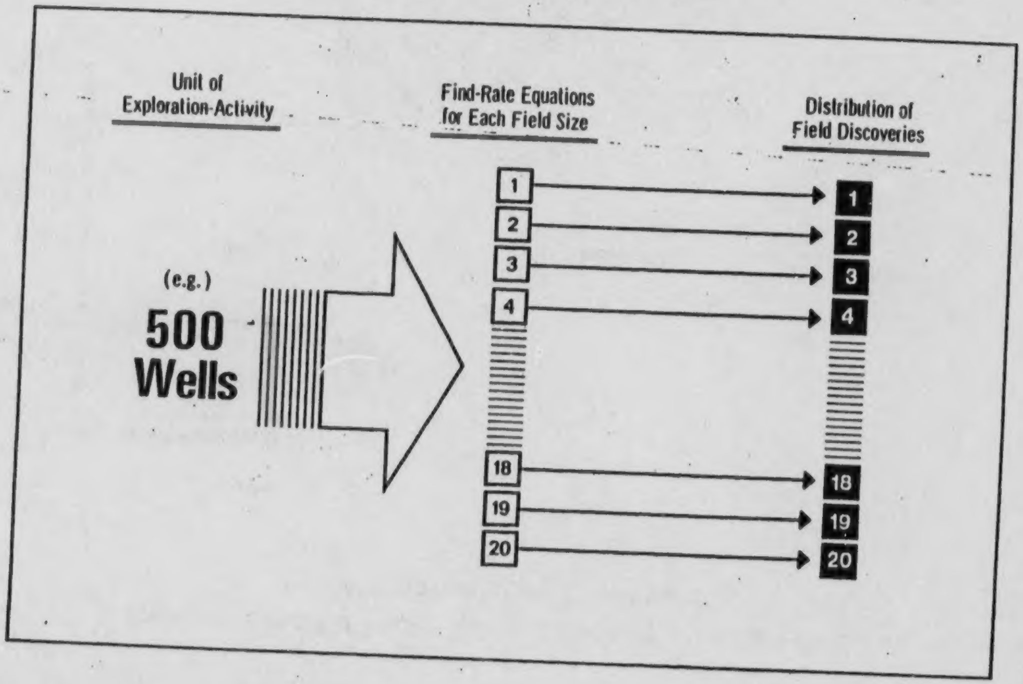
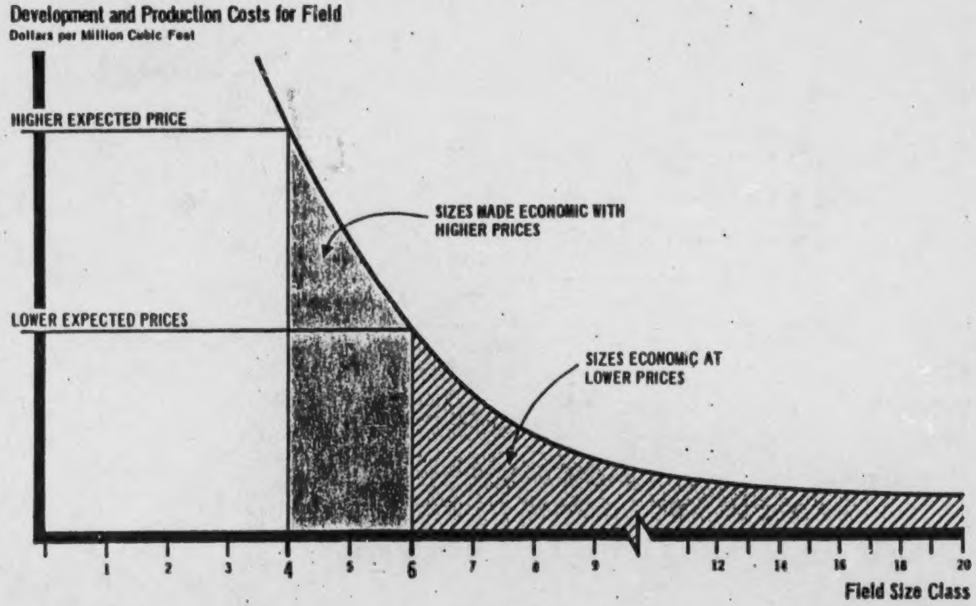

Unit of Exploration-Activity
Find-Rate Equations for Each Field Size
Distribution of Field Discoveries
(e.g.)
500 Wells
1
2
3
4
18
19
20
1
2
3
4
18
19
20

Figure 2

Based on Expected Prices, Model Calculates Minimum Field Size Worth Developing Once Found



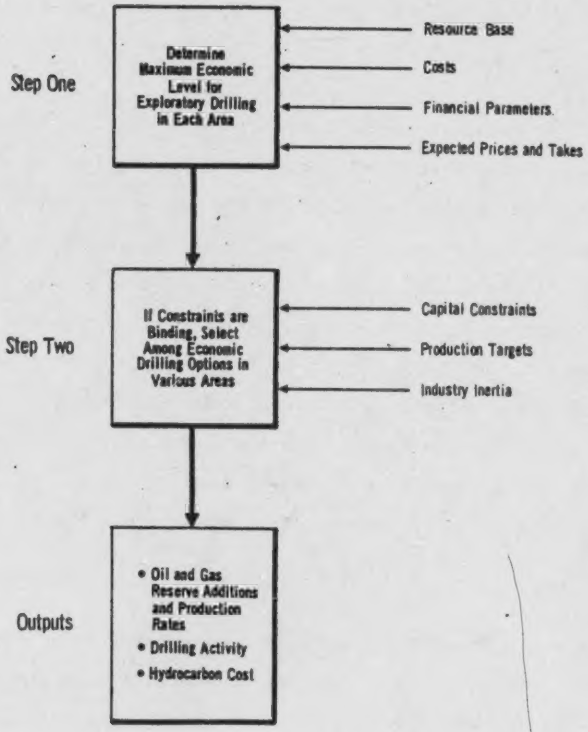
This procedure is repeated in the Hydrocarbon Model for higher and higher drilling increments for each region. If the total cash flow from an exploratory drilling increment along with the associated development and production meets the required rate of return, the next increment of 500 wells is tested. Eventually the process of resource depletion causes the rate of return at some very high number of exploratory wells to fall below the required level. The higher the oil and gas prices assumed in the model run, the larger the number of exploratory wells and reserve additions that will be economic.

When the model is run in a simulation mode, each economic increment of exploratory wells is placed in the model's "Options Table." This is Step 1 of the overall logic shown in Figure 3 and represents those drilling options which would be economic for the oil and gas industry to undertake. The order in which these options are taken in Step 2 depends primarily on their relative economics. After minimum exploration activities are achieved in all regions, the model then chooses those options with the highest return as measured by the profit index, i.e., the ratio of net present value to investment present value. The profit index is used in the model because it is widely used in the oil and gas industry[1] and because it is more easily computed than the best other option, internal rate of return.

The order and timing in which the options are exploited in the model may also be constrained by setting upper and lower limits on the total number of wells that can be drilled in any period (industry inertia), on the total expenditures that the industry can undertake (capital constraints), or by targetting a specific level of gas production.

Figure 3

Basic Structure of GRI Exploration and Development Model


Step One
Determine Maximum Economic Level for Exploratory Drilling in Each Area
Resource Base
Costs
Financial Parameters
Expected Prices and Takes
Step Two
If Constraints are Binding, Select Among Economic Drilling Options in Various Areas
Capital Constraints
Production Targets
Industry Inertia
Outputs
• Oil and Gas Reserve Additions and Production Rates
• Drilling Activity
• Hydrocarbon Cost

2. Financial Calculations

The method used in the model to evaluate investments is net, after-tax discounted cash flow. Investments that have an after-tax present value greater than or equal to zero when discounted at the minimum required rate of return are considered economic and may be undertaken in the model. In selecting among economic investments, the relative desirability of investments is measured by the profit index: the after-tax net present value of the investment divided by the before-tax present value of expenditures for the investment. Investment that have a rate of return exactly equal to minimum required rate of return have a profit index equal to zero. Investments with returns above the minimum have profit indices above zero. In general, the higher the rate of return, the higher the profit index.

The minimum required rate of return used in the model is usually 10 percent real, after-tax. If one assumes a 6 percent rate of inflation and a 40 percent average income tax rate, the nominal interest rate would be 27.7 percent if the investment were financed totally by debt or a nominal equity cost of 16.6 percent if financed totally through equity. The reason the translation into debt results in a higher rate is that a company's interest payments on debt are tax deductible and thus result in a lower after-tax cost. If the investment were financed 30 percent by debt and 70 percent by equity, the after-tax cost of capital of 10 percent could be translated into nominal cost of debt of 15 percent and a nominal cost of equity of 18.8 percent.[2]

The tax rates used in the model's financial analyses are those applying to large companies. Special tax breaks (e.g., percent depletion on new investments) accruing to small companies are not included in the model.

Moreover, all producers within each region and depth are treated as a single entity. For instance, when an exploratory well increment of, say, 500 wells plus all subsequent development and production activity for a particular area is evaluated, it is assumed that a single company is undertaking this activity.

Natural Gas Resource Cost Calculation

An important feature of the model is its calculation of the "resource cost" of gas. The resource cost of gas is defined as the price that would be needed to make the producer's after-tax rate of return exactly equal to the minimum rquired rate of return. Because the model treats exploration for both oil and gas as a single activity, exploration costs must be allocated in some manner between oil and gas in order for the resource costs of gas to be calculated. In the current version of the model, exploration costs are allocated on a BOE basis. If, for instance, an increment of exploratory drilling adds 40 million BOE of oil and 60 million BOE of gas, 40 percent of the exploratory costs are allocated to oil and 60 percent are allocated to gas in calculating the resource cost of gas.

Before the 1970s most gas was found as a by-product of exploratory activity directed toward oil. In that period oil, in effect, subsidized the exploration for gas. It is possible to hypothesize similar situations in the future whereby the gas resource cost is calculated with gas bearing only that portion of exploratory costs not recoverable from oil revenues.

Model Results

Two sets of model results are presented in this paper. One will be from the "producer" perspective and the other from the "gas purchaser" perspective.

Table 1 shows the target hydrocarbon prices used in the model runs. Oil prices grow 2 percent a year after 1985. Gas prices are targeted at $3.00 per BOE below oil prices to capture the effects of refining economics on residual fuel oil production and conversion.

Table 1
Target Prices
(1982$/BOE)

Year	Oil	Natural Gas
1980	36.25	33.25
1985	29.98	26.98
1990	33.10	30.10
1995	36.55	33.55
2000	40.35	37.35

In discussing the results of the Hydrocarbon Model, one caveat should be kept in mind. The oil production trends calculated by the Hydrocarbon Model do not include any oil production from enhanced oil recovery (EOR) of oil-in-place beyond that indicated by USGS estimates and DOE reserve estimates. Because the future recoverability of oil-in-place will probably increase over that estimated by USGS and DOE, the impact of incremental EOR activities on oil production trends could be significant. For example, in the 1970s over half of the lower-48 oil reserve additions resulted from increased recovery of oil-in-place. It is reasonable to expect that the inclusion of incremental EOR activities beyond those implied by USGS and DOE estimates would result in higher production than that calculated by the Hydrocarbon Model.

GRI plans to include the effects of incremental EOR activities on the trends in hydrocarbon production and costs in the 1983 Hydrocarbon Model development program. The introduction of EOR into the Hydrocarbon Model will increase lower-48 oil production, but because the price of hydrocarbons and oil in the Hydrocarbon Model is set by resource discovery and world oil prices, the inclusion of EOR is not expected to impact either resource or oil-based prices.

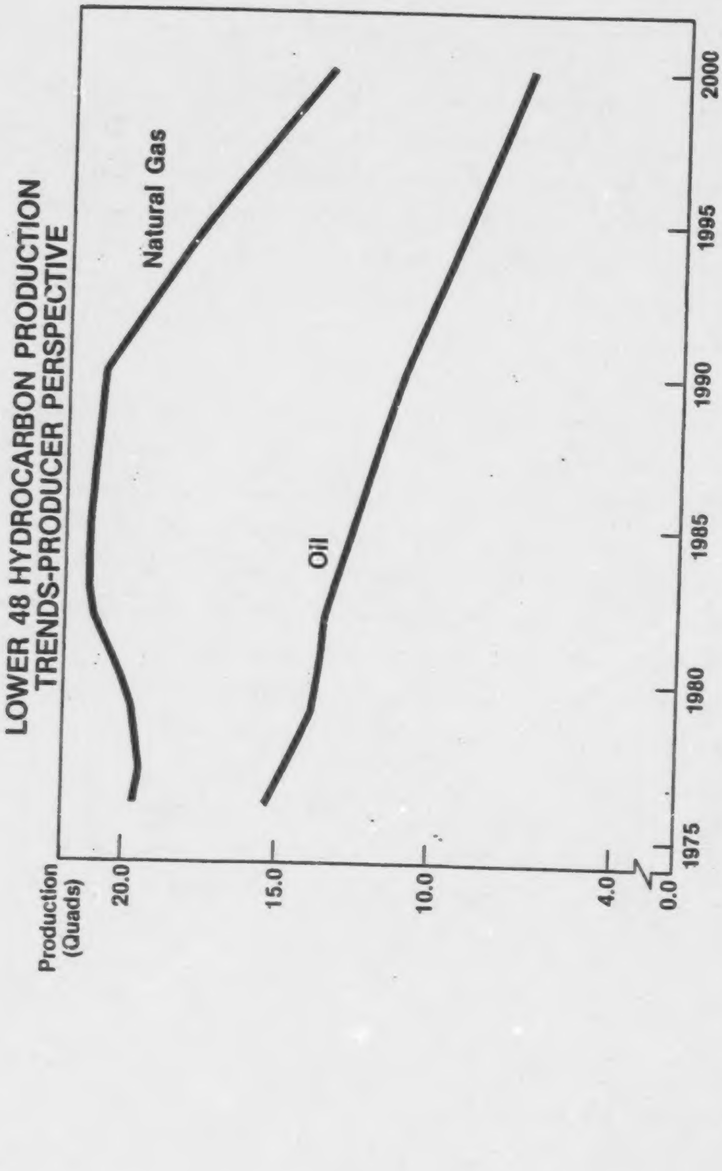
Figure 4 shows the projected trends in natural gas and oil production based on producer expectations (i.e., when the model solves for production consistent with assumed producer price expectations). It indicates the following:

- Natural gas production can remain over 20 Tcf throughout the 1980s. This is a result of the domination of natural gas production by gas fields discovered through 1980. Natural gas production declines steeply in the 1990s as production from the pre-1981 fields declines and the find rates for new gas fields fall.

- The steep declines in oil production estimated by the Hydrocarbon Model indicate that incremental EOR will be a very critical factor for future oil production. The extent to which the decline in oil production can be slowed will depend on the success of incremental EOR activities to increase recovery of oil-in-place above that currently estimated.

It is apparent from this figure that, given current exploration activity trends since the mid-1970s, the hydrocarbon industry could produce far more natural gas than most analysts expect the gas industry would be able to sell. The implications are that the rate of development and production of gas fields

Figure 4



LOWER 48 HYDROCARBON PRODUCTION TRENDS-PRODUCER PERSPECTIVE

discovered through 1980 would have to be slowed, exploration activity slowed, or some combination thereof. Otherwise, the gas bubble might not be a short-lived phenonmenon.

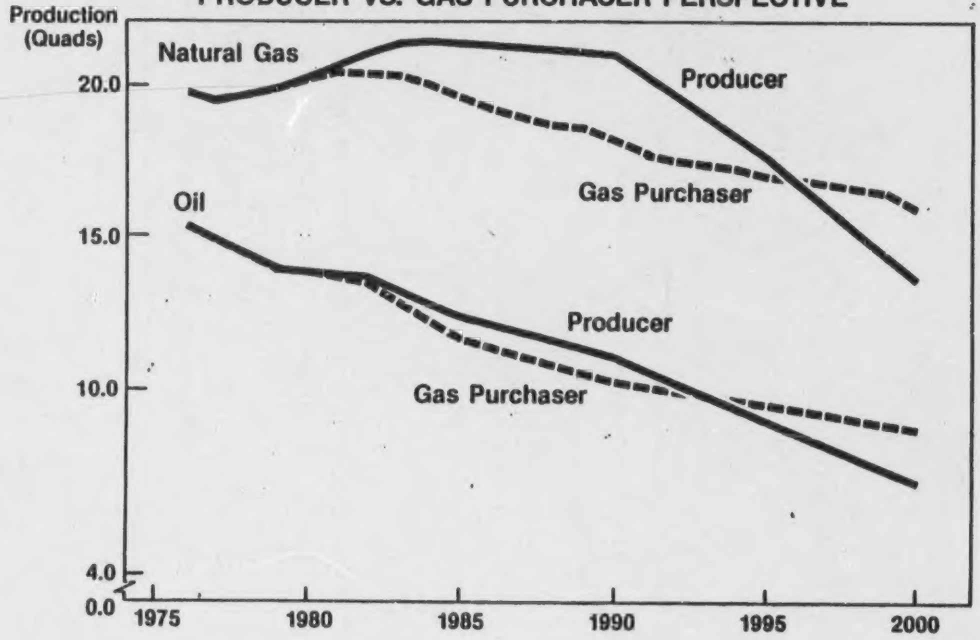
The previous calculations indicate a trend for natural gas production in the 1980s significantly higher than what the current consensus of potential gas consumption in the 1980s would appear to warrant. In addition, deferring some of this "gas bubble" to the 1990s might tend to moderate the decline in lower-48 natural gas production and the rise in prices in 1990s. Accordingly, a run was made from the "gas purchaser" perspective targeting gas production along a more consensus-like path.

Figure 5 shows the trends in hydrocarbon production from the gas purchaser perspective along with the producer perspective trends presented previously. The producer perspective run shows that lower-48 natural gas production remains over 20 quads through 1991, and declines steeply after 1990. By 2000, production is projected to decline to 14.6 quads. The gas purchaser perspective scenario, however, demonstrates a steady decline in production from 20 quads in 1980 to 16 quads in 2000. Oil production trends show a similar behavior, thus indicating that reducing gas exploration to eliminate the potential gas bubble in the 1980s would also reduce oil production as well.

Determining the wellhead price for natural gas is a highly complex process. Within the context of the target prices (producer expectations) and the resource cost for new hydrocarbon discoveries, a wide range of natural gas

Figure 5

LOWER 48 HYDROCARBON PRODUCTION TRENDS
PRODUCER VS. GAS PURCHASER PERSPECTIVE



wellhead prices can be derived. Figure 6 shows a range of the prices which could be derived for the producer and gas purchaser perspectives. Two general pricing categories are depicted:

- The target oil price, which is what the producer expects he could get before he undertakes his next increment of exploration activity.

- The marginal resource cost, which is the average price the hydrocarbons discovered in the next exploration increment would have to sell for if the producer is to realize a 10 percent real rate of return after taxes.

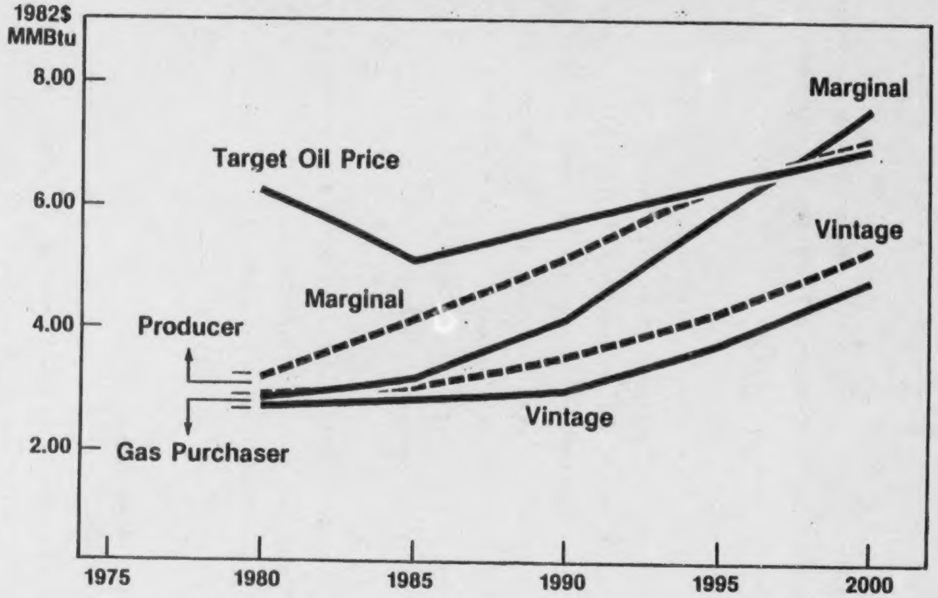
The marginal resource price is presented in the following two ways to capture the range of natural gas prices possible under two extremes of contracting procedures:

- "Marginal price" This is the weighted average marginal price of gas from all fields discovered in a given year. If this were used as the average price for natural gas, it would imply that all contracts included a "most favored nation" clause permitting prices for flowing gas to escalate annually to the marginal price of new gas fields. This represents an upper limit for gas prices.

- "Vintage" This price assumes that gas from each newly discovered field will continue to be sold until depletion at the real marginal price prevailing for that field at the initiation of production. If this were used for the average price of natural gas, it would imply that no escalation in contract prices would be allowed in excess of the inflation rate. This represents a lower limit for gas prices.

Figure 6

HYDROCARBON RESOURCE PRICE TRENDS
PRODUCER VS. GAS PURCHASER PERSPECTIVE



The following general observation can be made:

- In the 1980s, constraining new exploration activity in order to reduce gas production will result in less resource depletion and a significant decrease in marginal resource prices.

- In the 1990s, however, as exploration activity is accelerated to hold the decline in lower-48 natural gas production steady, the marginal price in the gas purchaser scenario begins to rise very steeply, until, by the late 1990s, the marginal price exceeds the marginal price of the producer scenario. This apparently counter-intuitive result comes about because the accelerated exploration activities in the gas purchaser scenario during the 1990s result in a more rapid depletion of the hydrocarbon resource base.

- Despite the rapidly rising marginal resource price in the 1990s, deferring exploration activity in the 1980s could result in a much lower vintage resource price through 2000 than in the producer scenario.

Hydrocarbon Model Status

The Hydrocarbon Model is a continually developing project. In 1983, GRI plans the following additions or improvements to the Hydrocarbon Model.

- Oil production resulting from incremental EOR activities will be included in the calculations of the trends in oil production and costs in the Hydrocarbon Model. These calculations will depict both the economic costs of EOR as well as assumed trends in EOR technology development.

- Currently, exploration constraints in the model are exogenously specified based on past experience. Development drilling is derived from exploration success, that is, the wells necessary to develop what is discovered. In 1983, exploration and development drilling activity will be explicity linked to the industry cash flows in the model.

- The Hydrocarbon Model will be expanded to include a pipeline model to calculate regional supplies and city-gate and burner-tip costs.

- The costs to develop natural gas in tight sands and Devonian shale will be explicity calculated with the Hydrocarbon Model framework. This work will utilize the results of the Tight Gas Analysis System currently being developed by GRI.

- Last, but not least, this year's development program will also include the development of a user-friendly access system for the Hydrocarbon Model.

Notes

[1] McCray, A.W., Petroleum Evaluations and Economic Decisions, Englewood Cliffs, NJ, Prentice-Hall, Inc., 1975.

[2] This is only one of many combinations of debt/equity splits and nominal debt and equity capital costs that are equivalent to 10 percent real after-tax rate of return.

TECHNOLOGY PLANNING DECISIONS

PRESENTATION BY DR. DANIEL A. DREYFUS
DIVISION DIRECTOR, STRATEGIC ANALYSIS AND ENERGY FORECASTING
THE GAS RESEARCH INSTITUTE

BEFORE THE
AMERICAN ASSOCIATION
FOR THE ADVANCEMENT OF SCIENCE
ANNUAL MEETING

DETROIT, MICHIGAN
MAY 28, 1983

The GRI Strategic Planning Problem

All business people, in one way or another, take into account the way in which economic systems impact upon their profit and loss situations. Recently, on a trip to New Orleans, I commented to a taxi driver that the restaurants were not busy and received a very quantitative discourse on the visitor count in the city, the weekly cycle of arrivals and the outlook for the summer season.

At my own office, I receive a number of costly subscription analyses of economic indicators and projections. My own motives and the cab driver's are identical. We both want to know how the economic environment is effecting our livelihood and we both want data to anticipate the future.

My livelihood, however, is somewhat removed from the immediacy of the next tourist season. The Gas Research Institute (GRI) is a private, not-for-profit membership organization that plans, manages, and develops financing for a cooperative R&D program in gaseous fuels and their use. The program is dedicated to providing near and long-term benefits that are in the mutual interests of the regulated gas industry and its customers.

There are several unique factors which complicate the application of economic and other strategic analysis to planning decisions in GRI. The first such factor is the long-range outlook and technological uncertainty which is generic to research and development organizations. By definition, planning decisions concerning research and development activities must be predicated upon judgments of the economic environment which will exist when the R&D effort comes to fruition.

GRI's R&D program includes projects which currently are, or are on the verge of, entering the market, but it also includes projects which, if successful, will have their application near the end of this century or beyond. The nature of R&D, therefore, requires GRI strategic analysis to consider the long-term future of the gas industry.

The second unique factor affecting GRI planning is a requirement to reduce normative analysis to quantitative terms. One of GRI's responsibilities is to justify its comprehensive R&D program before the Federal Energy Regulatory Commission (FERC) on behalf of its member companies. The FERC requires research project selection to be supported by objective, in other words, quantitative, benefit-cost analysis. A detailed and internally consistent set of projected economic data which is related to a GRI management view of the future is essential for such analyses.

The third significant factor which affects GRI's planning is generic to the regulated natural gas industry. The gas industry has evolved under a set of regulatory pricing constraints which has insured the competitiveness of available gas supply in many markets. The price escalations currently taking place under recent revisions of law along with the prospect of further relaxation of regulatory constraint have thrust the industry into a marketplace competition for which there is no relevant historical experience. GRI, in planning an R&D program to support the gas industry and its customers, must grope for a vision of a future which is unclear to the industry itself.

In summary then, GRI's strategic planning problem is to form a detailed, quantified, and long-term organizational view of the future of an industry which historically has been relatively stable, but currently is at a turning point.

The GRI Strategic Planning Approach

The strategic analysis function within GRI consists of two simultaneous activities. The first is the preparation annually of a comprehensive "baseline" projection to the Year 2000 of U.S. energy supply and demand. The second activity is an ongoing program of special analyses, conducted in-house and by contract, which focus on strategic issues of special concern to the economic future of the gas industry and its customers.

These programs are mutually supportive. The annual projection effort frequently suggests shortcomings in data or in comprehension of the external factors which affect the industry outlook. These shortcomings can be addressed by special analyses. The special analyses, in turn, improve the comprehensiveness, detail and validity of future projection cycles.

Finally, GRI views the results of the strategic analysis program as research products in themselves. In addition to the use made of strategic analysis internally in planning GRI's technical R&D program, the dissemination of the projection and the reports of special analyses are intended to benefit the gas industry and its customers by improving general comprehension of the industry's interaction with the economic environment, and the supply and demand outlook which confronts it.

The GRI Baseline Projection

The annual analytical process of preparing the GRI Baseline Projection serves several management purposes:

1) The annual reconsideration of major guiding assumptions for the projection provides the occasion for top management to reach an intuitive consensus about the general planning outlook for GRI.

2) The projection methodology insures logical consistency among the general assumptions and the comprehensive scenario developed in the models. Modeling of the projection provides a consistent detailed data base of projected economic, demographic, financial, and other parameters for use in program appraisal and technology assessment analyses during the planning and budgeting cycle.

3) The published summary of the projection and its backup documents provide means of communicating the GRI management view of the future throughout GRI; to its member companies, contractors, and advisory bodies; to the FERC and to others concerned with the GRI program and the outlook for the gas industry.

4) The preparation of the projection in conjunction with the program of special analytical studies comprises an ongoing program of research into the economics of the gas industry, its supply and demand dynamics, and its interface with its customers and competitors.

Baseline Projection Process

As in any planning effort, the process which is used to develop the GRI Baseline Projection is as important as the technical methodology. In fact, the interaction among top management, the strategic analysis staff, advisory groups and other participants are themselves important parts of the planning and decision process independent of the documentation of the projection.

It is self-evident that the most sophisticated analytical approach can contribute nothing to strategic planning if it is not integrated into the real management decision process. There are difficult obstacles to achieving integration, however, including limitations on access to top management, the inherent complexity of the analytical process, overt and suppressed disagreements among top managers about the normative and judgmental parameters for planning, and a robust skepticism on the part of many managers about the efficacy of any but intuitive projection methodologies.

Figure 1 represents the process for the preparation and approval of the annual GRI Baseline Projection.

GRI's formal internal top management group is known as the Operating Committee. It consists of the President, the General Counsel and seven other senior managers. The Operating Committee meets regularly and is the forum for day-to-day decisionmaking. The Operating Committee, in consultation with the Board of Directors, also is the strategic planning body.

The Operating Committee is directly involved in the Baseline Projection process at three critical points.

Initially, the strategic analysis staff makes a presentation to the Operating Committee outlining suggested assumptions for the projection. These assumptions include such major factors as the timing and pace of economic recovery and the short and long-term outlook for world oil prices. They also include less fundamental assumptions which are of particular significance to GRI, such as the initial natural gas prices to be used in the analysis.

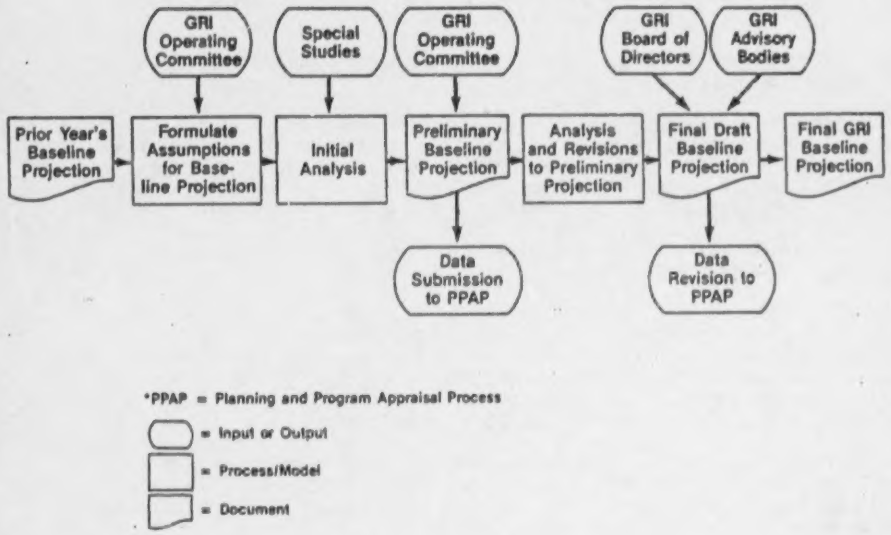
The Operating Committee is asked to address certain off-line stipulations which must be made judgmentally, such as the probable outcome of synthetic fuels project proposals. The Committee also reviews major proposed changes in the methodology used to prepare the projection.

The objective in this meeting is to highlight matters which involve basic judgments about the outlook for the economy or the gas industry and matters of special sensitivity to GRI's management. The agenda is kept as short as possible and the discussion focused on obtaining a general management view of the future.

The analytical staff provides suggestions and background information based upon general responses to the previous projection, analysis of new historical data, and a variety of external expert viewpoints. No effort is made to do orginal research within GRI about macroeconomic parameters, international affairs or similar general external assumptions. Rather, the best expert advice on such matters is collected and summarized by the staff. This information is supplemented where GRI has special expertise or where special studies have been undertaken, usually in areas relating directly to energy, especially natural gas, and economics or technology.

FIGURE 1

INTEGRATED ENERGY PROJECTION—METHODOLOGY PROCESS FLOW


GRI Operating Committee
Special Studies
GRI Operating Committee
GRI Board of Directors
GRI Advisory Bodies
Prior Year's Baseline Projection
Formulate Assumptions for Baseline Projection
Initial Analysis
Preliminary Baseline Projection
Analysis and Revisions to Preliminary Projection
Final Draft Baseline Projection
Final GRI Baseline Projection
Data Submission to PPAP
Data Revision to PPAP
*PPAP = Planning and Program Appraisal Process
= Input or Output
= Process/Model
= Document

The Operating Committee, therefore, is offered a synopsis of the best available information on the most important assumptions and asked to contribute its own considerable experience and judgment in refining the suggestions. In the course of the discussion, a management consensus about the general outlook evolves, and the Operating Committee develops a proprietary involvement in the projection process.

The strategic analysis staff fleshes out the general assumptions to the degree required by the projection methodology which will be described later. Considerable additional judgment and latitude is involved in this amplification, but the objective is to preserve consistency with the specific directions and general tone of the Operating Committee guidance.

A completed scenario or comprehensive projection of U.S. energy supply and demand is then developed by the analytical staff. Technical advice and direct involvement by other groups within GRI and by external advisory bodies also contribute to the development of the projection.

The Operating Committee again considers the comprehensive projection in preliminary form in a formal review meeting. At this point, the consistency of the detailed scenario with the judgments embodied in the chosen assumptions is reviewed and the implications of the results are discussed. Off-line adjustments or additional analysis then may be required to achieve an acceptable result.

Soon following this review, the preliminary projection is presented first to the Strategy Committee of the Board of Directors and then to the entire Board and to GRI's Advisory Council. The Operating Committee is present during these presentations and is involved in the discussion and the advice which results. The approved projection becomes the basis for program planning and is included in the presentation to the FERC in support of GRI's annual program funding application.

A summary of the projection is disseminated to GRI member companies and to other interested parties. Detailed backup data books are provided to the GRI staff which must use the information in analysis.

Baseline Projection Methodology

Several approaches which are applicable to constructing long-term projections or scenarios for strategic planning were considered by GRI.

Prior to the adoption of the current process, the GRI leadership annually formulated an intuitive long-range energy supply and demand scenario. The projection drew upon current projections by others and upon the experience and expertise available within GRI. This process had several shortcomings.

The intuitive process was "top down," proceeding from general concepts of the probable future, and it did not include a rigorous analytical framework, or accounting system. Therefore, no detailed disaggregation existed to back up the summary statements. For example, no regional breakdown of energy supply and demand quantities was available. Detailed energy prices and economic and demographic parameters related to the summary judgments were not developed. In fact, most such factors probably were not considered in generating the projection.

Hence, the detailed inputs for the technology assessment and program planning analyses which are needed to implement the strategic plan could not be derived from the strategic planning scenario. Such analyses, therefore, were often inconsistent with the projections and even among themselves, because case-by-case choices were made about analytical assumptions. Strategic planning was disjointed from implementation decisions.

Because there was no explicit framework for the projection methodology, each annual projection was made de novo, based primarily upon a contemporary set of outside projections. The methodology, therefore, did not grow, or benefit from the annual iterative process. No historical progression was available to rigorously relate changes in the outlook to causal factors in either the environment or the methodology.

Perhaps the most significant shortcoming from a strategic planning point of view was that the lack of a rigorous analytical framework or accounting methodology encouraged inconsistency internal to the projection. Analytical attention might be given to one aspect of the projection, such as residential energy demand, for which GRI possessed data and expertise, and then the results patched to a transportation sector projection which was a composite of contemporary outside work. Inconsistencies among guiding assumptions and the cross-sectoral relationships, such as petroleum refinery operations which supply both sectors, were not appreciated nor addressed.

The improved methodology, therefore, was designed to remedy those deficiencies. It was decided to develop an accounting framework, or model with the following specifications:

- The framework must generate a comprehensive scenario, or set of scenarios, of the U.S. energy supply and demand outlook for about a twenty year horizon (currently to the Year 2000).
- The framework must incorporate and maintain a historical data base and generate a projected data base to a degree of detail necessary to provide inputs for internal GRI analytical work.
- The framework should be comprehensive across all energy supply forms and demand sectors to an acceptable degree of detail.
- The framework should be capable of adaptation to GRI assumptions, logic modifications and substitutions, and should be capable of growth as special studies and experience provide better understanding of GRI's special interests.

An additional specification was that the framework should be capable of serving as a research tool. In other words, there should be a high probability that the GRI analysts would be able to use the framework to derive useful insights about the factors influencing gas industry supply and demand from the work done in the projection process and in associated sensitivity analyses.

Selection of Methodological Tools

The set of specifications set forth above quickly indicated that a major energy model service would have to be acquired as the basis of the framework. Only a relatively sophisticated model could conveniently and economically generate the wealth of backup detail required of the projections.

It should be emphasized that it was the requirement for a detailed data base which dictated complexity in the framework, rather than any notion that complexity was a criterion of the validity of the projections.

A projection was prepared using separate sectoral models and off-line synthesis among the results. This approach was found to be an unsatisfactory solution. Questions and data requests continually arose during the review process and in the use of the projection which straddled the results from separate analyses. Without an integrated framework, answers were unavailable and could not be readily generated. This experience indicated that the framework would have to formally integrate all energy sectors.

The framework which has now been adopted appears be meeting the requirements fully and offers several additional benefits.

The Integrated Framework

Figure 2 is a schematic representation of the integrated framework of analytical tools which are currently used for preparation of the Baseline Projection.

The principal integrating tool used for the projection is the Data Resources Inc. (DRI) Energy/Economic Modeling System, particularly the DRI Macroeconomic Model and the DRI Energy Model.

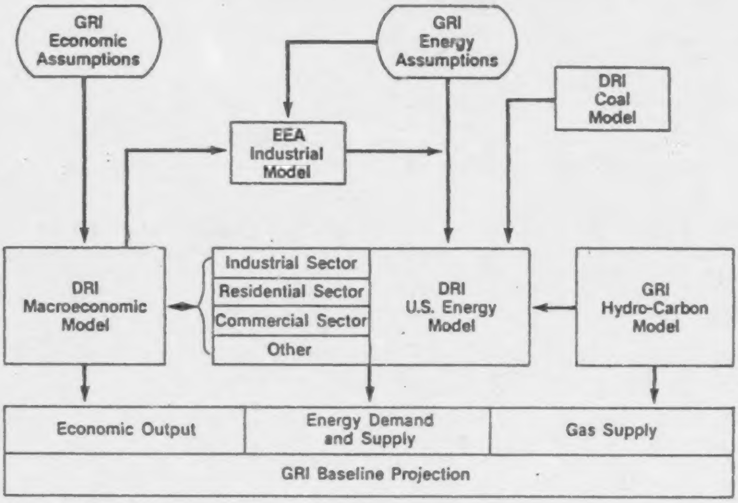
The DRI models were chosen for several attributes:

- The macroeconomic model explicitly recognizes the role of energy supplies, prices and imports in economic activity.
- The Energy Model is integrated with the macroeconomic model, is comprehensive across all energy forms and sectors and provides a balance between acceptable detail of output and reasonable requirements for input data.
- The model system contains an extensive historical data base which is compatible with the general data bases used by GRI and is maintained continuously.
- DRI offered consulting services and expert analytical support in economic and energy areas in which GRI has not developed in-house expertise such as the transportation sector.
- Finally, the DRI service is widely used by industrial energy users and energy companies including some GRI member companies. It serves as a form of informal information transfer to which GRI can contribute and from which it can benefit.

GRI uses the DRI models in a "hands-on" mode. DRI's regular advice to its subscribers is considered along with other sources in formulating the Baseline assumptions. Revisions to the DRI assumptions are freely, but not gratuitously, made by GRI. Usually, at the macro level, GRI's view is to change the DRI numbers only in order to adopt a more central or conservative position, or in areas such as energy price projections where GRI has done independent analyses.

FIGURE 2

BASELINE PROJECTION METHODOLOGY
INTEGRATED FRAMEWORK


GRI Economic Assumptions
GRI Energy Assumptions
DRI Coal Model
EEA Industrial Model
DRI Macroeconomic Model
Industrial Sector
Residential Sector
Commercial Sector
Other
DRI U.S. Energy Model
GRI Hydro-Carbon Model
Economic Output
Energy Demand and Supply
Gas Supply
GRI Baseline Projection

EEA = Energy and Environmental Analysis, Inc.
DRI = Data Resources, Inc.

In the energy model, however, the modifications made are much more extensive. GRI analysts work closely with the DRI staff in a run-by-run analytical process. Many independent inputs are made by GRI exogenously, and literally hundreds of modifications in the model's equations and parameters differentiate the GRI Baseline program from DRI's own projection runs.

The DRI family of models has also been supplemented for GRI's purposes by other independent tools.

For projecting the industrial energy demand sector, which is a particularly sensitive and significant sector for the gas industry, GRI also utilizes the Industrial Fuel Choice Analysis Model (IFCAM). IFCAM, which was developed by Energy and Environmental Analysis, Inc., is a large-scale process engineering model of energy use in industrial combustors.

After the DRI models have generated a reasonably balanced run, inputs derived from the DRI run are used to generate a calibrated run on IFCAM. IFCAM provides a technology-oriented breakdown of fuel choices, validation of the logic of the two models in an important demand sector, and a convenient tool to explore financial and fuel-switching decisions from a process or engineering viewpoint. Our experience has been that the convergence of the results from the two models is close enough to permit the IFCAM results to be directly adopted as backup to the Baseline Projection.

Currently, GRI is initiating a specal study to adopt or develop a similar independent analytical capability for the electric utility sector. The electric sector is significant to the gas industry in two ways. Not only is electric generation a major user of gas as a primarly fuel, but electricity is a major competitor with gas in many end-use applications.

Strategic planning for the gas industry depends heavily upon a judgment of the future role of gas as an electric generating fuel, and obviously the assessment of economic feasibility of many potential gas technologies rests upon projections of the probable price of electricity.

Electric prices for the baseline projection currently are generated within the DRI core energy model based upon projected demand for electricity and the model's representation of utility decisions. GRI believes that the significance of these factors warrants supplementary analysis in a more detailed model with special emphasis on utility financing considerations. The current plan would be to use the results of the special study to modify the DRI model and subsequently to use the new utility model to generate calibrated runs for validation and detailed backup data, as is now done with IFCAM.

On the supply side of the energy balance, GRI requires a detailed comprehension of the dynamics of natural gas production. The natural gas industry is emerging from a history of governmental price regulation into a future in which gas prices will be determined in a competitive market by a supply/demand equilibrium. There is no relevant historical data from which econometric projections of gas prices can be derived. Furthermore, projections of the quantities of natural gas which will be forthcoming at competitive prices are critical to judgments about the need for and timing of supply technologies which form an important segment of the GRI program.

GRI decided, therefore, that there was sufficient need and justification to construct a new hydrocarbon supply model. The GRI Hydrocarbon Model was developed under contract with EEA. The model is currently being used to derive gas price assumptions for the 1983 Baseline Projection.

The GRI Hydrocarbon Model provides a rigorous and consistent framework for analyzing the cost of finding, developing and producing natural gas and crude oil in the United States. The model has an extensive and detailed data base utilizing the generally available resource estimates supplemented by extensive, well-specific data surveys. It has a high degree of disaggregation among resource characteristics and cost elements and very explicit modeling of industry decisionmaking.

The Hydrocarbon Model will be used in conjunction with the demand models to arrive at an acceptable supply demand balance. The resulting projection will be able to provide a high degree of detail regarding the nature of the natural gas production associated with the gas demand and price scenario.

A supply-demand equilibrium will be developed by off-line iterations between the Hydrocarbon Model and the energy demand models and will impose a new level of consistency on the projection. This work also should reveal important strategic factors regarding the appropriate role of supply technologies to supplement conventional natural gas production.

Conclusion

The GRI Baseline Projection methodology, therefore, is an eclectic one. It incorporates intuitive judgment, econometric models, and engineering or process models within an integrated framework.

The models are used as data bases and accounting systems to insure that the interreactions among parameters are expressly addressed. The models, however, are viewed as tools. They are intended to force examination of relationships rather than to encourage blind acceptance of the results by the intuitive decisionmaker.

The modelmakers' judgments, knowledge and data are accepted wherever GRI has no independent information of its own, but validation is sought through comparison with other sources. Where GRI prefers its own judgment or information, the models are required to accept those inputs.

The complex integrated framework has only three objectives:

- to provide backup detail for other analytical work,
- to reveal interrelationships among sectors of the economic and energy environment, and
- to document the inputs and results of successive projections.

The framework is not considered to contribute certainty or clairvoyance to any greater extent than a purely intuitive projection. Rather, it is considered to inform and discipline the intuitive effort. Furthermore, no attempt is made to defend or protect the results of the framework. Adjustments are freely made off-line when the evidence of experience or simply management judgment indicates they are warranted.

Finally, the hands-on involvement of top management in the analytical process is jealously guarded. The complex analysis must remain always subservient to management insight and judgment.

If powerful analytical tools are invoked by staff to overwhelm and persuade rather than to support and enlighten the strategic planning process, the most confident, and usually the most influential, decisionmakers will soon reject the analysis in favor of their own views. At that point it becomes analysis for its own sake and the products are only reports.

At GRI, we want the products of strategic analysis to be decisions and corporate action.

Mr. FUQUA. Thank you very much, Dan.

[The biographical sketch of Mr. Oatman follows:]

EUGENE N. OATMAN

Eugene N. Oatman is the Manager of the Energy Resources Program, Energy Analysis and Environment Division, for the Electric Power Research Institute (EPRI) in Palo Alto, California. He is responsible for research in utility investment allocation and fuel supply planning. He joined the Institute in 1978 as Senior Member of the Systems Program Technical Staff. In January 1980, he was appointed Program Manager for Technical Transfer of the Rate Design Study, moving to his present position in May 1980.

Before joing EPRI, Mr. Oatman spent fourteen years at the Dayton Power and Light Company, most recently as Manager of the Planning Division, responsible for bulk power planning, forecasting, load management and corporate model development for the company.

He received a BSEE degree from Case Institute of Technology and an MBA from Wright State University in Ohio with partial requirements from the University of Santa Clara.

The author of publications on generation reserve planning, corporate modeling, and modeling under uncertainty, Oatman is a registered Professional Engineer in the state of Ohio, and has served as Chairman of the Power Engineering Society, Dayton Chapter IEEE, Secretary to the Board of Directors of the Dayton Engineers Club and member of the Advisory Council for the Charles F. Kettering Memorial Hospital.

STATEMENT OF EUGENE N. OATMAN, MANAGER, ENERGY RESOURCES DEPARTMENT, ELECTRIC RESEARCH INSTITUTE

Mr. OATMAN. Thank you, Mr. Chairman.

I have been asked to provide testimony on the use of price projections, forecasts and modeling to examine the impacts of lower oil prices on R&D planning at the Electric Power Research Institute. I have provided a copy of my testimony for the record.

In summarizing my testimony, I would like to refer to figure 1 that appears on page 4 of my prepared statement.

EPRI is the research arm of the electric power industry and is funded by voluntary contributions from individual operating utilities in the United States.

Figure 1 illustrates that EPRI's R&D program must be responsive to future utility strategies across a range of key uncertainties. This diagram links up the potential outcome resulting from the resolution of uncertainties in financial and demand growth to utility responses, and finally to the five R&D planning criteria that I will be discussing.

A hard lesson of the past decade is that the future is intractably uncertain. No level of sophistication will enable models to predict the future, nor is it given to mortal decisionmakers to choose desired futures from scenarios of uncertain outcomes. The insights sought from modeling uncertainty should be that, accepting the future as complex and uncertain, what actions can be taken to best position the utility industry in that future and to mitigate the impacts of contingent events.

Since EPRI's R&D policy must, above all, be consistent with utility strategic plans, R&D options must relate to the range of possible utility strategies. In the face of uncertainty, utility decisionmakers focus on those alternatives that actually are under their control.

These decisions reflect perceptions of future demand growth, financial risk and regulatory treatment as well as current financial health and economic outlook. Moreover, because of long construction lead times, these decisions can have effects over extended planning horizons far beyond the customer's ability to forecast electricity demands.

Models can help utility and EPRI R&D planners structure the complex network of relationships and uncertainties that link the needs and responses of individual customers, utility strategies and R&D requirements; but there is no universal comprehensive model that adequately represents all relationships and all stakeholders. Rather, a system of models and forecasts that address specific issues and relationships can be applied within a consistent framework to develop an integrated R&D strategy.

A key uncertainty is whether the utilities' financial situation will be "balanced" or "tight." A balanced financial situation is defined here as being able to recover all the costs of providing service and to earn a return on invested capital at least equal to the cost of that capital.

A tight financial situation would represent a continuation of the experience of the past decade of less than full recovery of costs and earned returns less than the cost of capital. A tight financial situation would likely be characterized by high inflation and/or increasing real costs. The latter might be due to higher fuels cost or increasing requirements for environmental control equipment.

The current and perceived financial situation bears substantially on the way a utility views life and makes decisions. Tight financial conditions force utilities into capital minimizing strategies that heavily discount the future. A balanced financial situation facilitates total cost minimizing strategies where all the decision factors are more equitably traded off over the long term. Adding the uncertainty in demand growth further differentiates these strategies into cost and capital minimizing strategies for high and low growth.

Demand growth captures information about prices of electricity and its substitutes as well as overall economic growth. Low growth implies combinations of high electricity prices relative to other fuels and sluggish economic conditions.

Adjacent to the utility strategies in the figure are listed the five R&D planning criteria used by EPRI to evaluate specific research projects and areas. Of greatest significance is the fact that the EPRI R&D program does not hinge upon specific forecasts of major uncertainties such as world oil prices. Although changes in relative emphasis and timing of particular research areas and individual projects may occur as perceptions about these uncertainties evolve, the R&D criteria remain relevant because they embody the fundamental factors of success for the electric utility industry.

Even if the likelihood of various outcomes cannot be determined, certain R&D needs are common across utility strategies. Under a number of possible outcomes, utilities will be interested in clean, short lead time, modular technologies that do not tie up capital resources over extended periods of time and that provide a closer match to incremental changes in demand. Full utilization of existing nuclear and coal capacity is essential to holding prices down for both high and low growth outcomes under both balanced or tight financial conditions.

New and improved coal-burning technologies are important for meeting environmental requirements and for increasing productivity to make electricity more competitive. Finally, increased end-use efficiencies, load management, and new electricity-using technologies will help slow the eventual depletion of petroleum-based energy and enable electricity, as a unique form of energy, to fully realize its potential contribution to the economy.

Utilities and EPRI planners use projections of primary energy prices and availability as inputs to a broad set of models that are used in conjunction with the planning framework. These models are used to gain insights into the nature and likelihood of possible outcomes, to help utilities develop appropriate cost and capital minimizing strategies for those outcomes and to balance the emphasis among R&D options corresponding to those utility strategies.

As the dominant energy commodity in the world, oil price uncertainty affects utilities in complex ways and, consequently, figures prominently in many of these models. Effects of oil prices on electric utilities include the direct use of oil as a utility fuel, substitution effects at the end use, sensitivity of the overall economy, and contribution to the rate of inflation. Several recent studies that address the possible impacts of lower oil prices are discussed in the following sections.

Turning to the effects of lower oil prices on direct use of fuels for electricity generation, a recent study for EPRI by Charles River Associates examined the interfuel competition among coal, oil, and gas in the Southeast and Gulf States region. The study concluded that the large price differential between the costs of baseload generation from coal and comparable costs for new oil and gas facilities still makes coal the choice even under lower oil prices. Moreover, lower oil prices are unlikely to have a significant effect on coal prices as sufficient competitive forces exist in coal mining to hold down prices at the mine-mouth.

Forecasts of mine-mouth prices of coal over the next decade project average real price increases of around one percent. However, the effects of depletion and stringent environmental regulations that require large shifts to low sulfur coal easily could double that rate of increase. Coupled with transportation rates under the Staggers Act that can increase up to 15 percent per year without regulatory review, it is possible for electricity prices to rise in real terms in the face of stable or declining oil prices.

Oil price forecasts within the reasonable range of expectation are unlikely to affect the choice of coal or nuclear for new capacity. However, lower oil and gas prices can affect the rate of planned conversions from oil and gas to coal, especially in light of siting and acidic deposition legislation uncertainties.

Next, I would turn to effects of lower oil prices on electricity demand growth. The effects of oil prices on electricity demand can most readily be examined through the concept of price elasticities associated with econometric modeling.

The consensus of results of studies from a variety of models across a variety of low oil price scenarios is that flat or declining oil prices have a negative effect on the demand for electricity. If both electricity and oil and gas prices are flat, then electricity could be expected to grow at a rate approximating that of the GNP. If, however, oil and gas prices are flat, or declining, and electricity prices continue to rise because of increasing construction and coal prices, then electricity demand growth would be less than the GNP.

Finally, I would summarize the effects of lower oil prices on the development of substitute technologies. The objective of the sixth EPRI-sponsored energy modeling forum study conducted by a 43-member working group was to analyze world oil issues through the application of 10 prominent world oil or world energy models to 12 scenarios designed to bound the range of likely future world oil market conditions. The world oil study contains an underlying assumption that, over the next several decades, reserves of low-cost oil and gas will become depleted. As depletion occurs, prices will rise, signaling the potential profitability of substitutes, or so-called backstop technologies. Because of the lead time required to develop and commercialize these backstop technologies, oil prices will continue to rise above, or overshoot, the backstop price until the nondepletable technologies become proven. That the transition will occur is inevitable. The timing will depend upon the course of world oil prices in a nondisrupted world oil market.

The world oil study contends that the unmistakable long-run trend in oil prices is upward, although the participants concur with other forecasters that slack oil prices are likely to persist well into this decade.

In conclusion, the preceding examples are illustrative of the wide range of models used in support of informed decisionmaking by the electric utility industry and EPRI to develop corporate strategies and R&D policies that are resilient over a broad range of uncertain outcomes. These models and forecasts can provide insights into the effects of important factors, such as oil prices, on the demand for electricity, direct utility costs, and financial conditions. They cannot, however, see the future and unpredictable events may cause large discontinuities in the structural relationships represented.

The preliminary analysis on the impact of lower oil prices reaffirms the importance of industry and EPRI efforts to minimize total revenue requirements through innovation, productivity, and flexibility.

That concludes my statement.

Mr. **Fuqua**. Thank you very much, Mr. Oatman.

[The prepared statement of Mr. Oatman follows:]

TESTIMONY BY EUGENE N. OATMAN

No level of sophistication will enable models to predict the future, nor is it given to moral decision makers to choose desired futures from scenarios of uncertain outcomes. Consequently, the insights sought from modeling uncertainty should be that, accepting the future as complex and uncertain, what actions can be taken to best position the utility industry in that future and to mitigate the impacts of contingent events.

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Models can help utility and EPRI R&D planners structure the complex network of relationships and uncertainties that link the needs and responses of individual customers, utility strategies and R&D requirements; but there is no universal comprehensive model that adequately represents all relationships and all stakeholders. Rather, a system of models and forecasts that address specific issues and relationships can be applied within a consistent framework to develop an integrated R&D strategy.

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The current and perceived financial situation bears substantially on the way a utility views life and makes decisions. Tight financial conditions force utilities into capital minimizing strategies that heavily discount the future. A balanced financial situation facilitates total cost minimizing strategies where all the decision factors are more equitably traded off over the long term. Adding the uncertainty in demand growth further differentiates these strategies into cost and capital minimizing strategies for high and low growth. Demand growth captures information about prices of electricity and its substitutes as well as overall economic growth. Low growth implies combinations of high electricity prices relative to other fuels and sluggish economic conditions.

In the diagram adjacent to the utility strategies in the figure are listed the five R&D planning criteria used by EPRI to evaluate specific research projects and areas. Of greatest significance is the fact the EPRI R&D program does not hinge upon specific forecasts of major uncertainties such as world oil prices. Although changes in relative emphasis and timing of particular research areas and individual projects may occur as perceptions about these uncertainties evolve, the R&D criteria remain relevant because they embody the fundamental factors of success for the electric utility industry.

Even if the likelihood of various outcomes cannot be determined, certain R&D needs are common across utility strategies. Under a number of possible outcomes, utilities will be interested in clean, short lead time, modular technologies that do not tie up capital resources over extended periods of time and that provide a closer match to incremental changes in demand. Full utilization of existing nuclear and coal capacity is essential to holding prices down for both high and low growth outcomes under both balanced or tight financial conditions. New and improved coal-burning technologies are important for meeting environmental requirements and for increasing productivity to make electricity more competitive. Finally, increased end-use efficiencies, load management, and new electricity-using technologies will help slow the eventual depletion of petroleum-based energy and enable electricity, as a unique form of energy, to fully realize its potential contribution to the economy.

Utilities and EPRI planners use projections of primary energy prices and availability as inputs to a broad set of models that are used in conjunction with the planning framework. These models are used to gain insights into the nature and likelihood of possible outcomes, to help utilities develop appropriate cost and capital minimizing strategies for those outcomes and to balance the emphasis among R&D options corresponding to those utility strategies. As the dominant energy commodity in the world, oil price uncertainty affects utilities in complex ways and, consequently, figures prominently in many of these models. Effects of oil prices on electric utilities include the direct use of oil as a utility fuel, substitution effects at the end use, sensitivity of the overall economy, and contribution to the rate of inflation. Several recent studies that address the possible impacts of lower oil prices are discussed in the following sections.

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Next I would turn to effects of lower oil prices on electricity demand growth:

Simple econometric models.—The effects of oil prices on electricity demand can most readily be examined through the concept of price elasticities associated with econometric modeling. The behavior of the real price of electricity, the behavior of the real price of oil and natural gas substitutes for electricity, and the behavior of personal income and industrial output.

The concensus of results from a number of models across a number of low oil price scenarios is that flat, or declining, oil prices have a negative effect on the demand for electricity.

If both electricity and oil and gas prices are flat, then electricity could be expected to grow at a rate approximating that of the GNP. If, however, oil and gas prices are flat, or declining, and electricity prices continue to rise because of increasing construction and coal prices, then electricity demand growth would be less than the GNP.

Finally, I would summarize the effects of lower oil prices on the development of substitute technologies:

The objective of the sixth EPRI-sponsored Energy Modeling Forum (EMF) study conducted by a 43-member working group was to analyze world oil issues through the application of 10 prominent world oil or world energy models (Figure 4) to 12 scenarios designed to bound the range of likely future world oil market conditions. The World Oil study contains an underlying assumption that, over the next several decades, reserves of low cost oil and gas will become depleted. As depleted occurs, prices will rise, signaling the potential profitability of substitutes, or so-called backstop, technologies. Because of the lead times required to develop and commercialize these backstop technologies, oil prices will continue to rise above (overshoot) the backstop price until the nondepletable technologies become proven. That the transition will occur is inevitable. The timing will depend upon the course of world oil prices in a nondisrupted world oil market.

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SUMMARY OF RESEARCH RESULTS ON PRICE AND INCOME ELASTICITIES FOR ELECTRICITY

	Residential		Commercial		Industrial	
With Respect To:	Range	EPRI[a]	Range	EPRI[b]	Range	EPRI[c]
Price of Electricity	-.5/-1.3[d]	-1.05	-.3/-1.6	-.3	-.2/-2.0	-.23
Price of Natural Gas/Other Fuel	0.0/.3	.02	0.0/.5	--	0.0/.5	.12
Income	.5/1.6	.8	.4/1.6	.46		
Output					.7/1.2	1.07

Sources:

[a] Residential Demand for Energy, EA-1572 Vol. 1, April 1982, Table 6-3.

[b] Demand for Energy in the Commercial Sector, EA-2330, March 1982, Table 4-3.

[c] Dynamic Adjustment Models of Industrial Energy Demand, EA-1613, November 1980, Table 5-3, 5-4.

[d] The range of the price elasticity is -.5 to -1.3

Figure 2

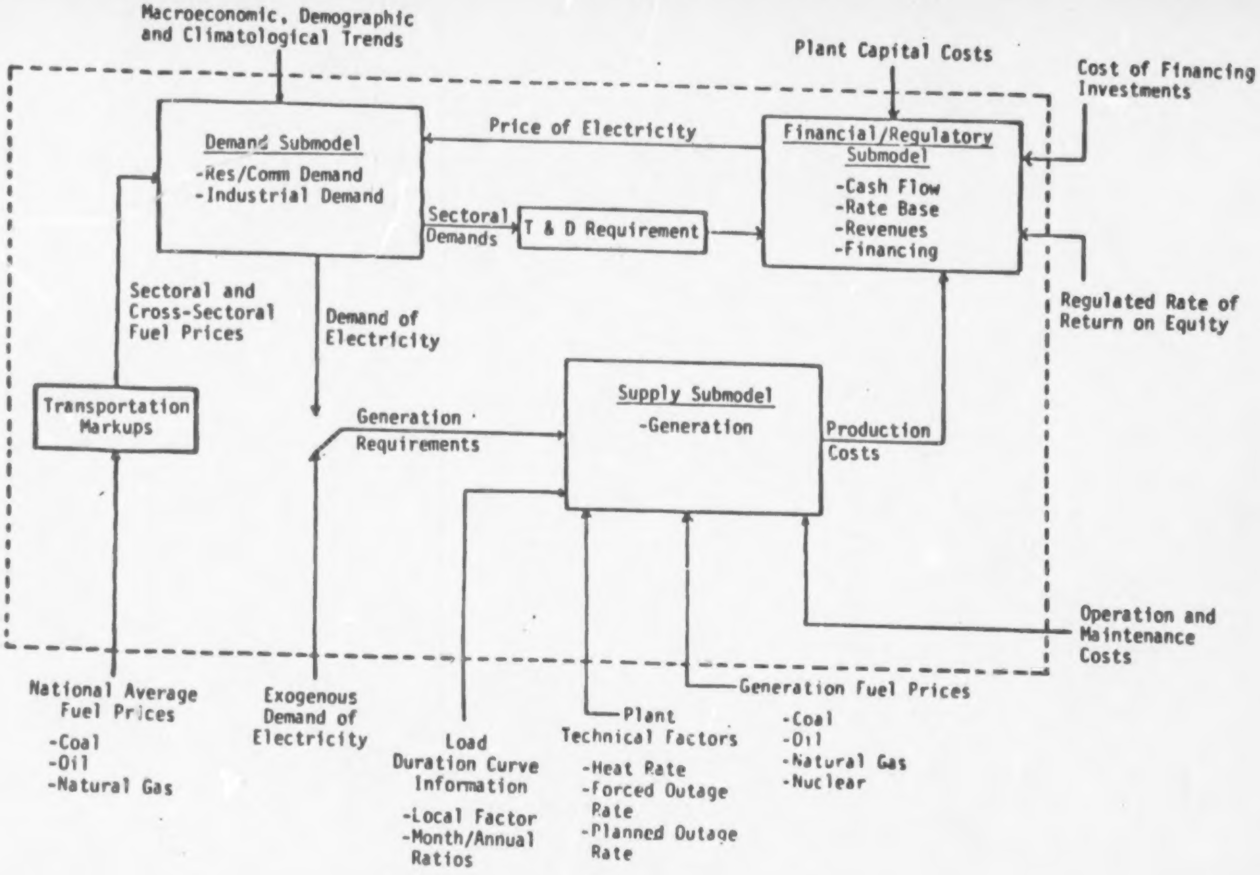
Macroeconomic, Demographic and Climatological Trends
Plant Capital Costs
Cost of Financing Investments
Demand Submodel
-Res/Comm Demand
-Industrial Demand
Price of Electricity
Financial/Regulatory Submodel
-Cash Flow
-Rate Base
-Revenues
-Financing
Sectoral Demands
T & D Requirement
Regulated Rate of Return on Equity
Sectoral and Cross-Sectoral Fuel Prices
Demand of Electricity
Transportation Markups
Generation Requirements
Supply Submodel
-Generation
Production Costs
Operation and Maintenance Costs
National Average Fuel Prices
-Coal
-Oil
-Natural Gas
Exogenous Demand of Electricity
Load Duration Curve Information
-Local Factor
-Month/Annual Ratios
Plant Technical Factors
-Heat Rate
-Forced Outage Rate
-Planned Outage Rate
Generation Fuel Prices
-Coal
-Oil
-Natural Gas
-Nuclear

Figure 3 Schematic of Calculations Done by REM

MODELS USED IN THE WORLD OIL STUDY

Model	Representative(s)	Organization(s)
Gately-Kyle-Fischer	Dermot Gately John Kyle	New York University Imperial Oil Ltd.
IEES-OMS (International Energy Evaluation System-Oil Market Simulation)	Calvin Kilgore	U.S. Department of Energy
IPE (International Petroleum Exchange)	Nazli Choucri	Massachusetts Institute of Technology
Salant-ICF	Stephen Salant William Stitt	U.S. Federal Trade Commission ICF, Incorporated
ETA-MACRO	Alan Manne	Stanford University
WOIL	John Stanley-Miller	U.S. Department of Energy/ Energy and Environmental Analysis, Incorporated
Kennedy-Nehring	Michael Kennedy Richard Nehring	University of Texas Rand Corporation
OILTANK	Leif Ervik	Chr. Michelsen Institute
Opeconomics	John Mitchell	British Petroleum Co. Ltd.
OILMAR	Frank Potter	Energy and Power Subcommittee, U.S. House of Representatives

Figure 4

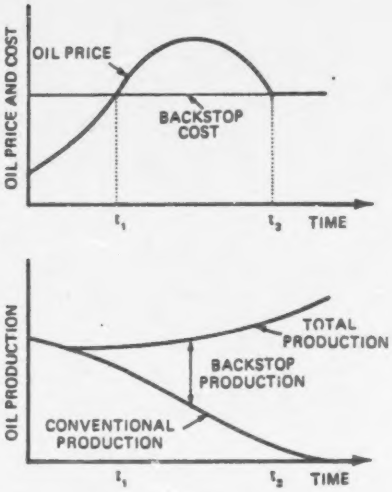

Figure 5 Transition to the Backstop

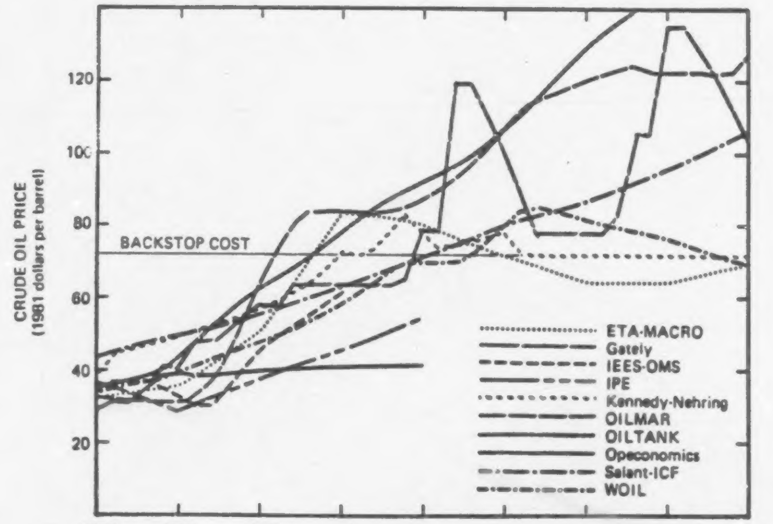

Figure 6 Crude Oil Price versus Backstop Cost for the Reference Case

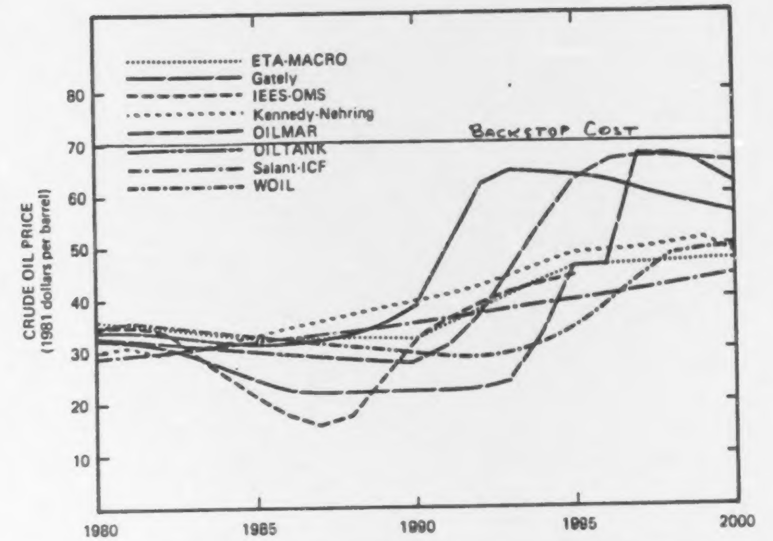

Figure 7 World Oil Price Projections for the Optimistic Scenario

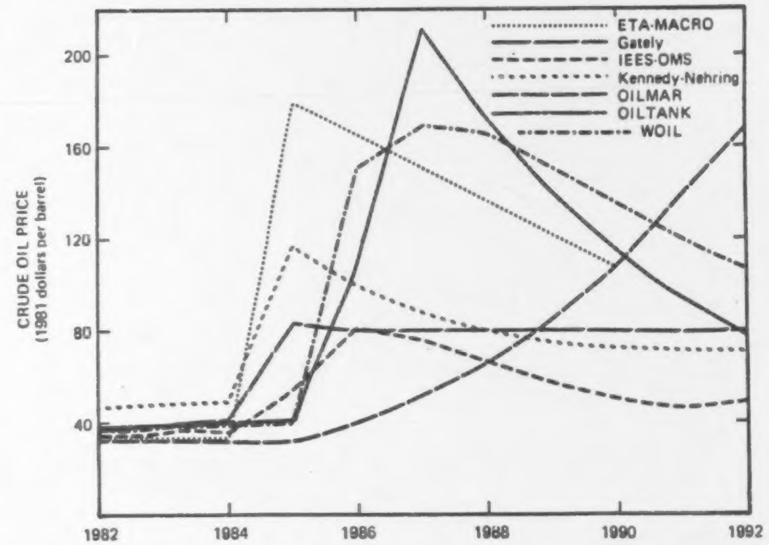

Figure 8 Disruption Case World Oil Prices

Mr. FUQUA. Dr. Adelman.

STATEMENT OF DR. MORRIS A. ADELMAN, PROFESSOR OF ECONOMICS, MASSACHUSETTS INSTITUTE OF TECHNOLOGY

Dr. ADELMAN. I want to thank you, Mr. Chairman, for the invitation to appear here and testify.

I would like to go back 5 years. In 1978, as today, the consensus was for stable prices for the near term. It seemed to make sense. There was a persistent glut and if world oil were a competitive market, there could have been no increase. But oil prices were unstable then—and are now—because they are set by a strong but clumsy cartel; strong because in the face of a 50-percent loss of exports, they have reduced prices by only 15 percent. Clumsy because they raise prices by cutting production and this is a process where small cuts can have violent effects.

Buyers are quick to panic. They demand much more than is being or will be consumed and so production may exceed consumption and yet, demand may exceed production driving prices up.

In 1973, 1974, and 1981, the sequence was the same. First, there were two sharp production cuts by Saudi Arabia and associates. This caused the price explosion in the short term or spot markets. This was followed by a gradual increase in list prices long after the brief shortage had given way to surplus. It was known as following the market. There is nobody here but us market followers. But they had created or rigged the market to begin with.

There was a glut in 1974, yet prices were raised in steps by 50 percent between January and October. During the second explosion in June of 1979, Saudia Arabia assured the Tokyo summit that they, the Saudis, would never let the price go as high as $20. "Never" did last very long. Twenty-seven months later, in October of 1981, in an unprecedented glut, they finished the process by raising the price to $34.

Now, there are only two possible ways for the price to be lowered in these circumstances. First, the cartel may decide the price is really too high because it costs them so much business that it lowers their profits. There is no indication whatever that the cartel nations think that $34 was really too high. Nor should they think so. Nobody knows where their optimal or ceiling price is.

Second, a sales dropoff and cartel nations jostle for extra business. They begin to chisel and cheat and undercut. This has happened, of course, and last March they retreated efficiently and stabilized the front a short way back. But as soon as they think cohesion is regained and they can count on each other again, their first order of business will be how far, how soon can they raise the price.

To some extent, the cartel nations have been scared into greater caution than previously. Against this must be set their financial problems.

Outside the North Sea, all of the oil exporting nations are in balance of payment and budget deficit today. Some of them are in acute difficulties and all are overspent or overcommitted. They are hungry. They feel trapped and it may make them reckless.

We could have a new price explosion at almost any time. All we need is for the OPEC nations, with the cooperation of Britain, Mexico, and the Soviet Union, to hold production down to current levels in the face of a strong upturn in world economic activity.

Our real problems are this continued instability and the cartel nations' attempt to use any remaining unexerted market power they don't have to raise the price again.

The worry of the model builders about long-run scarcity, about increasing pressure of consumption on limited resources is farther away from reality than ever.

The huge low cost reserves that pressed upon prices before 1970 are still there, larger than ever. The discoveries in Mexico are not as cheap as the best Middle East but would cost a negligible fraction of current prices.

The supply problem, in fact, cannot be divorced from the monopoly problem. The response of a competitive market to a higher price is: greater investment and output. In the United States, the number of wells being drilled is three times that of 1973. But a monopoly does not respond to the price, they make the price and cut back production to maintain it. And so, in Saudi Arabia, the number of oil wells being drilled is about half that of 1973.

The usual assumption that oil output in the cartel nations will not grow, for lack of reserves, turns reality on its head. They will not invest money to increase reserves or even use current reserves because only by restricting output can they maintain prices.

Turning now to policy: every shortage known has been brief, and the shortfall in supply has been small. In fact, usually negligible. Even today the strategic petroleum reserve is big enough to handle anything we have known or are likely to know. It is not, however, enough for the unlikely catastrophe and it should be large enough for that. But even for the likely minor crisis the SPR must be in operation before the crisis arrives.

I have suggested one such plan which is at least simple, maybe too simple and there may be better plans around, but one should be in place.

The second suggestion, we should listen carefully to Sheik Yamani. A month ago, he threatened that if any consuming country levied an import tariff on crude oil, Saudi Arabia would retaliate against that country's exports. He is telling us that the exporters would bear much or most of the burden on a tariff. It would be a transfer from their treasuries to ours. He has good reason to object to that and we have equally good reason to welcome it.

I think that even where I come from, in New England, where they get livid at the mention of a tariff, it would be good for us and it would be good for the United States.

The third point is our R&D policy. Four years ago, I happened to be testifying before a committee of this House at the height of the scare and I begged them to cast a cold and pennypinching eye on synthetic fuels projects. Things aren't as bad as I might have feared, but if you will look back at Mr. Mares' photograph which was over on the easel and which is in his prepared testimony, you can see at a glance what is wrong.

If all of those blocks could be reversed and the big one at the left-hand side, we would be a great deal better off. As it is, we are spending large amounts of money to learn what we know already, synthetic fuels are not worth producing. We can buy oil much more cheaply and that means even including a proper security premium which is the cost of an adequate SPR. Current technology is not worth practicing and the only sensible goal is new technology to make cheaper oil or gas or to clean up coal or provide other sources or other savings.

The large-scale research program would cost a small fraction of the waste of synthetics. How much of the research would turn out to be science and how much engineering is one of the things we would learn on the way.

I would remind the committee that most minerals—finite, limited and all that—most minerals have declined in price over the years, despite the constant attrition of known reserves. There has been only reason for this, increasing knowledge, both of the Earth's crust and of new methods of finding and exploiting mineral deposits.

Much R&D is done by private industry where there is promise of profit for those making the discoveries. But some kinds of knowledge promise great benefits for everyone but not for the discoverer.

He has no way of keeping it to himself for his own gain. That is where Government action is needed. Abolishing the Synthetic Fuels Corporation and funding a program of basic research in synthetic fuels, for example and related subjects, would save some money immediately, would save some good brain power from waste and might give us massive benefits in the future. We will never know if we don't try.

Thank you, Madam Chairman.

[The prepared statement of Dr. Adelman follows:]

M. A. Adelman
Department of Economics & Energy Laboratory
Massachusetts Institute of Technology

The world oil price is now about 10 times the 1970 level. It has been highly unstable since. Even a subtantial decline, say 25 percent in real terms since the 1980 peak, does not quite amount to "lower oil prices" as the basis of policy change.

The current consensus is that world crude oil prices will be fairly stable in the near future, but then will go higher again around 1990. But that was also the opinion in 1978, when there was a palpable glut, and most OPEC nations were in financial trouble. We could be wrong again, perhaps not quite as egregiously.

My opinion is that stability in world oil prices will not be seen in the near future any more than in the recent past. Forces are working to push oil prices both up and down. Supply is unstable because it is in the hands of a strong but clumsy cartel. Policy must conform to this world.

I think it is simply wrong to ask what policy is appropriate in view of supposed lower oil prices. We should rather ask: what policy is appropriate for an uncertain and dangerous future?

SOME PAST EXPERIENCE

One purpose of building the various energy and economic models is to try to pick up longer run trends. Many such models have been built, and it is well that they should be, because they enrich the knowledge of both builders and readers. But using them as predictors is chancy, to say the least.

The famous CIA report of 1977 (repeated in its essentials in 1979) estimated that by 1985, the "need" for OPEC exports would be 44 million barrels daily (mbd). In June 1978,the International Energy Agency calculated 1985 need for OPEC oil at 45 mbd and "available" OPEC production at 37.

In the first quarter of 1983, OPEC exports were approximately thirteen (13) mbd. They will surely fluctuate up --and down-- in the near future, but few now expect them to reach even half of that 44 mbd. Some recent forecasts mention 25 mbd, give or take one, by the year 2000.

These models were relatively simple and crude, but that was minor compared to a bad theory of the market: a permanent shortage of oil resulting from inexorably rising "need" for oil on the one side, and on the other a preference by big producing nations for keeping their oil in the ground. It is not easy to say how many later models incorporate that theory, because the structures become so complex.

There were more sophisticated models, some of which did treat the export nations as a monopoly. Published in or before 1979, they were nearly unanimous in calculating an optimal price around $13, which happened to be the OPEC marker price just before the 1979 price explosion. Something was missing.

Today there is again a confident expectation: that by say 1985 the rise will again start, and that prices will triple or more, in real terms, by the early 21st century, rising at 5 percent or more per year.

The unspoken major premise is of growing demand pressing upon limited resources. This is exactly what has not happened worldwide. The prediction, or projection, has no basis in experience or logic. (See below, remarks on Supply.)

I would recommend to your attention a model by my colleagues Jacoby and Paddock, appended to this testimony. Instead of trying to predict what will happen, it aims rather to show the bounds of any prediction: how high or how low the price can go before setting up such strong counter-forces that it cannot rise or fall farther. The gap between high and low is distressingly wide, but that merely reports the fact. I would add that relatively small causes can have large effects in jolting the price up or down.

THE ELEMENTS OF A MODEL: (1) DEMAND

A model of oil prices must incorporate three elements: demand, supply, and market control, or monopoly. I think our knowledge of demand has advanced greatly since 1973, though as usual the more we learn the more we wonder.

Higher oil prices have slowed world economic growth. Every industrial country, without exception, shows a strong down-deflection at 1973.

The less developed countries (LDCs) seemed for a time more resistant than the industrial countries. Many borrowed to keep importing to keep growing. Now they must cut back imports with double severity to keep solvent. The situation is worst in Latin America. Growth will be slow and hesitant.

Over and above the allowance for slow growth, it is clear that oil consumption is strongly responsive to price. U. S. oil consumption this year is running at about the 1970 level, despite a GNP which is about 36 percent higher.

The amount of oil used per unit of GNP has been shrinking since 1973, and will keep shrinking for years because the reaction to higher prices is slow. Mostly it is replacement of long-lived capital assets, and replacement of fixed ideas. That takes time, it is hard to say how much. Based on average lifetimes of capital equipment, I would suggest that the effects of the 1973 price shock have not yet been exhausted, still less the bigger 1979 shock.

However, the strength of the response varies greatly among types of consumption, and among countries. The data are not only incomplete but very disturbed. Even the best econometric analysis is only an orderly summation of the past, and the system has been pushed beyond any past experience. Therefore I do not know how well our analyses are capturing a movement which is wide, deep, and with many complex interactions. But oil consumption is static or slowly declining.

THE ELEMENTS OF A MODEL: (2) SUPPLY

Much less can be learned about supply, and models are correspondingly weak. The theory requires knowledge of resources and reserves, and the cost of developing resources into reserves, and too little is known of both.

A book on resource and reserve measurement, by four authors including myself, will be out in a few months. [Adelman, Houghton, Kaufman, and Zimmerman, Energy Resources in an Uncertain Future, Ballinger 1983] It explains, often by example, how we analyze the kinds of data we have. There is a long way to go.

Worse yet,the data base is actually shrinking. The reserves reports of the American Petroleum Institute and American Gas Association have ceased, victims of mindless hostility to the oil industry. Their continuation by EIA is not nearly as good. For example, we no longer have the series showing oil and gas reserves discovered in new fields, year by year, in the light of hindsight. We could compare this with measures of expenditures, by year. That series is gone. All we have left is a series labeled "discoveries", but this gives only a small unstable fraction of the new fields' contents: that part which happens to be developed in the discovery year.

Outside the United States: the expropriation of the oil companies in the Middle East and elsewhere, and the turmoil since, has made even the production figures suspect. The quality of the reserve data, never very high, has deteriorated, as has other information relative to supply.

Many of the models seem (I use the word advisedly) to incorporate a notion of lower cost oil disappearing, and gradually rising costs pushing prices up over the years. That theory is the contrary of what has been happening. It is a curious phenomenon: high cost oil is being used up while low cost oil is not.

For example, in the U. S.(net of Alaska, which only started up in the middle of the period) end-1973 reserves were used up 1.27 times, and replenished, in 1974-82. There is strong evidence that the reserves which replaced those produced and used up were of much inferior quality, i. e., higher cost.

If the whole world were like this, one could explain higher prices, but of course not prices as high as currently.

In contrast, cumulative output of Saudi Arab oil during those years was not 127 percent of reserves but little over 11 percent. Replenishment was probably at higher cost, but still negligible by comparison with even past let alone current prices. Similarly with the other Persian Gulf countries.

More than offsetting the very small attrition of low cost reserves since 1973, there have been the discoveries in Mexico which are not as low cost but are still ultra cheap in relation to current prices.

Scarcity of reserves, and rising costs, cannot possibly explain what has happened, and are no basis for economic projections. Hence my earlier dismissal of the consensus so popular today, of steadily rising prices after 1985.

There is only one reason to expect rising prices for any mineral over time. It is rational conduct to work the better mineral deposits first. Going from deposit to deposit, or depleting a given deposit, one goes from good to bad and from bad to worse. As costs rise, prices must rise to cover them, and the anticipation of even higher costs and prices gives rise to a premium which makes prices rise even faster than costs.

But this is not happening. The low cost reserves are being held off the market, which strongly suggests deliberate restriction to maintain or raise the price, i. e. market control or monopoly.

(I should observe, in passing, that for nearly all minerals, real or inflation-adjusted prices have declined over time, because the constant attrition of known reserves has been more than overcome by greater knowledge: of the Earth's crust, and of better extraction methods. But "general principles do not decide concrete cases". For any given mineral in any given time and place, anything can happen. That underlines the importance of research and development in minerals, including oil and gas.)

ELEMENTS OF A MODEL: (3) MONOPOLY

Monopoly, which interacts with demand and even more with supply, is the hardest to analyze.

That raises quite a problem. If one of the three decisive factors is left out of an elaborate model, we may learn a lot about the other two in building the model, and therefore our time may be well spent. I think that is usually the case. But the predictions are not necessarily any better than a crude once-over-lightly model would yield, which covered all three.

The best we can do, I suspect, is to follow Florence Nightingale's principle: whatever a hospital does, it must not spread disease. We may not be able to say much about monopoly, but at least we ought not to ignore the facts that outside this country, oil discovery and development do not fit the competitive pattern.

INVESTMENT RESPONSE UNDER COMPETITION AND MONOPOLY

The response of a competitive market to a higher price is: greater investment and output, as has happened in the United States with oil and (despite many distortions) natural gas. Drilling is nearly three times as great as in 1973, even with the current slump.

But a monopoly, such as that of the OPEC nations, does not respond to a price, it makes the price. In order to maintain a high price, it cuts back investment to restrain capacity and production. In Saudi Arabia, drilling is down by 50 percent. Of 49 known Saudi oil fields, only 15 are in operation. This makes it impossible to estimate reserves, other than developed reserves, with any accuracy.

This behavior makes nonsense of any model based on scarcity.

Back in 1973, when Saudi production was 7.6 million barrels daily, Aramco expected to raise production gradually to 20 million barrels daily by the mid-1980s. (It is around 4 or 5 today). Thus when someone assumes that production in the cartel nations will not grow, because reserves will not grow, he turns reality on its head. The truth is that money will not be invested in increasing reserves or even in using current reserves *because* high prices restrict sales.

The lack of a monopoly theory leaves a vacuum, often filled by arbitrary assumptions, sometimes with geopolitical overtones, about the behavior of the oil exporting nations. These myths have been very influential.

"OIL EXPORTERS WOULD RATHER KEEP OIL IN THE GROUND"

Supposedly, the OPEC nations limit production because they only want enough money to satisfy their "needs". No evidence has ever been offered to support this unlikely story.

In fact, each time the price exploded, the imports of the oil producers exploded too. As a group the oil exporting nations quickly managed to spend even more than they received. The 1974 OPEC current-account surplus of $84 billion went to zero in four years. The $115 billion surplus of 1980 disappeared in only two years, and the OPEC nations are running a current-account deficit. Even Saudi Arabia managed a budget deficit in 1978, and a much bigger one this year.

The Saudis assured us many times what a "sacrifice" they were making in producing 7 or 8 million barrels daily; how much they wanted to cut back production, say to 5 or even three mbd. Their neighbors and partners would have loved that. In fact, like all the other exporting nations, they have maneuvered, negotiated, and threatened, to achieve higher quotas. It is all completely normal behavior in a cartel. A model which omits it is doing Hamlet without the prince.

PECULIARITIES OF THE CARTEL

But every cartel is a historical individual, recognizably different from every other. On the whole, though not in every single respect, the OPEC cartel is a much better fit to the economists' abstract cartel model than are any private cartels.

No group of private companies could raise the price of an important raw material tenfold, with heavy damage to the world economy. Even aside from antitrust laws, there are plenty of ways in which a government can limit or even destroy a private monopoly. But there are no such constraints on a group of governments.

Few if any cartels have found it worth while to appoint a special task group to ascertain their long-run ceiling price, as set by the price of substitutes they cannot control; that is what a special OPEC ministers' committee reported on in February 1980.

But even strong cartels are fragile compared with a single-seller monopoly, because they must reconcile the various opinions of the members about what is possible, and also their divergent interests. A higher price is better for the high- cost producers, a lower price for the low-cost.

But the most intractable problem is dividing up the market among the cartel partners. It becomes a problem in political coalitions, formed and broken. Everybody wants to have a bigger quota. It pays to cheat if one can get away with it, so there must be detection and enforcement machinery. Bickering is divisive, bargains will not be kept for long. Hence cartel control is likely to be unstable.

If and when a common decision becomes impossible, the cartel must go to a fallback position, or second-best: the few biggest producers assume the burden of restraining output, while the others produce to the limit. The oil exporters' cartel sometimes appeared to be heading that way, with the Gulf Arabs taking the burden, but the severe shrinkage of demand for their oil has made that imposssible, at least for the time being. This uneasy oscillation has not been captured in any model, to my knowledge.

ADDITIONAL PECULIARITIES: MOSTLY HELPFUL TO CARTEL

Revolution and war are always likely in areas like the Persian Gulf; in Iran and Iraq, they have immobilized producing capacity of about 8 million barrels daily, some of it perhaps for all time. Ancient hatreds and modern ambitions, both fed by oil money, have taken a heavy toll of lives, and threaten to turn the Persian Gulf into a dead sea covered by an oil slick. But to immobilize huge blocks of capacity is good for oil prices.

The Gulf Arab states are reported to be spending $1 billion monthly to keep the war going. This is another way in which higher prices choke off investment, decrease capacity, and thereby support still-higher prices. If there were a price collapse, the Persian Gulf war would soon flicker out for lack of money, and capacity and production would climb, further weakening prices.

Another peculiarity also strengthens the group. Their accumulated foreign exchange assets are only a small part of past revenues, but they are large absolutely. It enables them to resist the pressure to cut prices. Had they been strapped for cash, they would have been forced to compete to a damaging maybe ruinous degree.

WHY CARTEL PRICE MAY GO HIGHER

There is no indication that anyone in OPEC thought the $34 price too high, and wanted to reduce it to increase total sales volume. The price decrease was forced on them by lack of cohesion, cheating on price, and the fear of losing even more sales to cheaters. Once cohesion is restored, and it seems to be on the mend, their next order of business will be: how far can we raise the price?

Here is another respect in which the OPEC cartel is different from a private cartel.The members have all overspent or overcommitted their revenues.Their financial problems will make them more anxious for short run gains and less attentive to long-run loss of sales. They are not more far-sighted than private companies, quite the contrary.

Even the wealthiest of them feels hungry, with big money problems, and it makes them a bit reckless. The only question is: can they get away with it again? Admittedly, wherever the ultimate price ceiling may lie, they are a lot closer to it. An increase to $40 would be feasible, and perhaps profitable. But above that, matters become more doubtful, not only because of consumer substitution, but because of the effects on world economic growth.

In the short run, however, there is no limit but the sky.

CLUMSY CARTEL MAKES PRICE EXPLOSION ALWAYS LIKELY

The cartel can only protect its price by limiting output and dividing the market. Unfortunately, nobody can fine tune with very coarse instruments.

Consumption data are many months old, and inaccurate even in the OECD countries, because there is no information whatever on "downstream" inventories, i. e., those held by distributors and consumers. For that reason alone, I would regard 1979 consumption figures as so "polluted" that they should not be used at all. And 1982 numbers may be shaky too, though I trust not as much. Even the formerly well regarded numbers on oil-company inventories are not only slow in coming in, they have apparently "misbehaved" in the last three years. That may be why oil company short run forecasts have gone peristently wrong.

Outside the industrial countries, prompt consumption figures hardly exist. Even production data are no longer accurate, because they have become so politicized.

The OPEC production control mechanism has been wound very tight: down to 17.5 million barrels daily of production, which means 15 mbd offered as exports. More than that will be demanded if there is a continuation or strengthening of the modest recovery now going on.

But the market signals are late and unclear. There could easily be a small shortfall, production below consumption. Inventories would decrease, at just the moment when the oil trade thought it time to start rebuilding them. The amount demanded could go well above the amount supplied. Yet nobody can actually observe this process, or know it has happened until months have gone by. Hopes for a pickup in sales have been disappointed again and again these last few years. It would seem like common prudence to delay increasing production quotas for another month, until the cartel was sure of the revival. If in doubt, wait another month. Add now a touch of worry over deficient supply, a dash of hope of making some inventory gains. Buyers start to over-order, spot price rise strongly--and we are off to the races again.

THE SAME PROCESS IN 1973-4 AND 1979-81

In 1973-4 and 1979-81, the sequence was very similar.

Two sharp production cuts by Saudi Arabia and associates caused a price explosion in the short term or "spot" markets. Then there was a gradual increase in list prices long after the brief shortage had given way to surplus. This was called "merely following the market". But the exporters had fixed or manipulated the market before following it.

There was a glut in 1974, and prices were raised in steps by about 50 percent between January and October.

The second explosion was not caused by the Iranian Revolution, since the lost output could easily have been made up. President Carter thought he had a deal to that effect. But there were two Saudi production cuts, in January and April, which made spot prices explode.

In June 1979, Saudi Arabia assured the Tokyo summit that they would "never" let the price go as high as $20. "Never" did not last long. Twenty seven months later, in October 1981, when the glut was unprecedented for length and severity, they finished the process by raising the price to $34. They thought they could ride out the glut, as they did in 1974, and by and large they have succeeded.

In a word: the cartel is strong but clumsy. They cannot avoid brinkmanship, and we have to live with it. Unstable prices, supply crises and shortages, are very likely; higher prices are likely too, but we cannot tell whether they will stick.

IF CARTEL COLLAPSES: IMMEDIATE AND LONGER RUN EFFECTS

I think the odds are against a cartel collapse. To test the strength of any thing or system, put it under strain. From 1979 to 1982, OPEC lost over 50 percent or more of exports, yet they yielded only 15 percent on price. Moreover, the threat of still lower prices has brought them the cooperation of Great Britain, Mexico, and Soviet Russia.

However, even an improbable event is worth pondering if it helps our understanding of the oil market. What would happen if price chiseling and cheating got out of hand?

At a 1970 price of $1.25, about $3-$5 at 1983 prices, there was a perceived glut. Since the low cost reserves which overhung the market then are still there, and consumption outside the Communist areas is at about the 1970 level, the initial price could hardly be above $5.

Oil consumption would increase greatly, in direct response to the lower price, and because of faster economic growth. There would be much greater attrition of the low-cost reserves. Higher depletion rates would raise costs, and the anticipation of yet-higher rates would generate a premium: thus prices would tend to rise more than development costs.

But there would also be substantial additions to reserves. The cartel logic works in reverse too. If exporters each acted individually, as competitors, then particularly for those with large unused reserves or promising prospects, a drastic increase in production and new capacity would be the only way of salvaging something from the wreck, and offsetting some at least of the loss in revenues.

An end to the Persian Gulf war would quickly increase production and investment to restore and increase capacity in Iran and Iraq. Kuwait would get back to producing 3 or more million barrels daily instead of the less than one today. In Saudi Arabia, they would again start exploration, which is nearly dormant today.

But we have no way of knowing how large these additional reserves would be. It is prudent to assume they would not fully offset the increased consumption, and that development cost and price would rise substantially, converging toward some long run number above $5, perhaps over $10, but nowhere near today's prices.

There is a formidable "backstop" in the form of "heavy oils". In Venezuela, the deposits could be made into 700-1000 billion barrels of reserves by investment in production and upgrading. That exceeds total world proved reserves today. It would set a cap on world oil prices around $15, for a long time ahead.

CONCLUSION

I have indicated the market forces--demand, supply, and monopoly--which any model, simple or complex, must include if it is to predict. Most attention has been paid to monopoly because it is the most complex and most difficult to understand and manipulate. It points to a future as turbulent as the recent past, but with large errors possible or even likely in any forecast.

Let me make two brief remarks before turning to energy R & D policy. Every oil shortage known has been brief and the real shortfall has been small, usually negligible. Even today, the Strategic Petroleum Reserve is big enough to handle anything we have known or are likely to know.

But there must be some kind of plan for having it in operation before the crisis arrives. I have suggested one such plan which is appended to this testimony. It is at least simple; there may be better plans around, but one should be in place.

In addition to having the SPR ready to unload, we should also listen carefully to Sheik Yamani, who a month ago was threatening that if any consuming country levied an import tariff on crude oil, Saudi Arabia would retaliate against that country's exports.

He is telling us that he and other exporters would bear much or most of the burden of a tariff. It would be a transfer from their treasuries to ours: good for us, bad for them.

Turning now to R & D: Four years ago, testifying before a House committee, I begged them to cast a cold and penny-pinching eye on synthetic fuels projects.

The Synthetic Fuels Corporation expect to have $13 billion committed a year from now. There will be little impact on the budget, we are told, before the end of the decade. That's when the chickens will be coming home to roost. We are spending large sums to learn what we know already: synthetic fuels are not worth producing.

We can buy oil much more cheaply, even including a security premium, which is the cost of an adequate SPR. Current technology is not worth practicing.

If we tried, we might create a new technology whereby oil or gas could be made available more cheaply and securely than they are today, or whereby coal could be used without the environmental damage it does today. The attempt would cost a small fraction of the wasted money poured out on synthetics. What we need is basic research. How much of it turns out to be science and how much engineering is one of the things we would learn on the way.

For all the talk of limited and finite and nonrenewable and irreplaceable, etc., the fact is: most minerals, by far, have declined in price over time, despite the constant attrition of known reserves. This has been the fruit of increasing knowledge. Exploration is merely a form of R & D.

Much R & D is done by private industry where there is promise of profit for those making the discoveries. But some kinds of knowledge promise great benefits for everyone, but the discoverer has no way of keeping it to himself for his own gain. That is where government action is needed, and I think it is long overdue.

Abolishing the Synthetic Fuels Corporation, and funding a program of basic research in synthetic fuels, and related subjects, would save some money immediately, would save some good brainpower from waste, and might give us massive benefits in the future. We will never know if we don't try.

Coping with Supply Insecurity

M. A. Adelman
Professor of Economics
Massachusetts Institute of Technology
Cambridge, Mass. 02139

INTRODUCTION AND SUMMARY

Since the end of World War II, there have been six world oil supply disruptions, in 1951, 1956, 1967, 1973, 1979, and 1980 – one year in six, and the frequency seems to be increasing. This danger will continue, for there are many sources of disruption. Although the probability of any one type in any one year is low, the chances of escaping them all for several years are also low.

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An oil glut does not prevent disruption. Indeed the OPEC attempt to evade the 1978 glut was the direct cause of the 1979 shortage.

Some disruptions have had only negligible price effects, some have been devastating. Supply *crises* are a demand phenomenon. Our problem is not a slightly lower output but a surge of demand for hoarding, prompted by uncertainty and self-fulfilling fear. Therefore, it is useless and pernicious for governments or the IEA to calculate a supply "shortfall" and try to redirect supplies.

Public stockpiles can mitigate a crisis, and very likely prevent it altogether, if we let prices govern the rate of use. We should renounce price controls and allocations, domestic or international. The cost of stockpiling should be covered by a permanent security tariff, convertible into a disruption tariff.

All this would seem to be in tune with the philosophy of the current administration, but I fear that harmony is more apparent than real.

A BACKWARD GLANCE

In 1948, there began a set of escalating restrictions on crude oil imports into the United States, first by congressional committee, then by the Texas Railroad Commission, then by a "voluntary" program, and finally by mandatory controls in 1959. Foreign oil supply was deemed "insecure" but just why, and to what extent, was never seriously analyzed until 1970.[1]

In 1967, after the Middle East war, I wrote a paper defining the problem as a temporary disruption. I recommended large-scale stockpiling of oil (and also coal in coastal power stations), and I opposed subsidies to domestic production, or "diversification" among sources that might fail at the same time for the same reason. The paper was published in French, Italian, and Japanese, but I could not get it published in English, though the *Petroleum Economist* (then *Petroleum Press Service*) carried an excellent summary.

In the summer of 1973, as I had the previous year in Japan, I made a tour of eight European countries to ask various persons in government and industry what was being done to assure security of oil supply. Shortly after I finished a draft report, it was overtaken by events: the war and the "embargo." Accordingly, I put the draft away. Small loss, because all it said was: "Nothing will come of nothing." Nothing was being done for security in Europe and Japan because it was hoped that somehow nothing would happen. There was much discourse about political accommodation with oil producers, of "cooperation, dialogue, and interdependence." We continue to hear it.

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[1] Task Force on Oil Import Control, *The Oil Import Question* (1970).

I. NATURE OF THE PROBLEM

We address not the long-run problem of the average price paid to oil-exporting nations and the average amount they will produce, but rather sudden unforeseen fluctuations in supply which produce amplified fluctuations in price. The need to distinguish these issues is hidden by the fruitless controversy over whether we face a "glut" or a "shortage." Whatever happens, we will face temporary disruptions, for various reasons.

Embargoes, Cutbacks, Political Strife

Another "embargo" like that of 1973–74, though less likely today, is possible. An embargo is inherently inefficient because in order to hurt one or two buyers, one must hit everybody by a general production cutback. The target nation cannot be cut off, because of swapping customers and supplies, diversion of shipments, and trans-shipments. In 1973–74, the United States was hurt less than Britain and France. The world oil market, like the world ocean, is one great pool.

The oil companies deserve high marks for doing efficiently in 1973–74 what would otherwise have been done sloppily, slowly, and at higher cost. But if oil becomes more scarce in any one nation, the price there rises swiftly relative to other places. Anyone with an available cargo can make large amounts of money by shipping it there. This thwarted the oil embargo of Italy in 1935, and the Arab embargo of the United States and the Netherlands in 1973.

It is curious how the nations refuse to accept the fact of a single market and remain obsessed with particular suppliers – the biggest or second biggest one, etc – and the supposed need for its good will.

An embargo is a deliberate act with intent to injure. The 1973 embargo was a violation of treaties of commerce, navigation, and friendship with the United States. The violation might not be covered up next time, as it was then. It would risk deliberate retaliation.

A more important danger than a deliberate production cutback is the fact that nearly all major exporters are undemocratic and unstable. The Outs can displace the Ins only by conspiracy and violence. Iran should have, but did not, teach us the lesson: avoid close friendship with the Ins.

These countries are also mostly unruly and lawless toward each other. (Saudi Arabia has been no exception.) And, unfortunately, internal strife makes external aggression more likely. True, the Iraqis, when they attacked Iran, recalled that they first taught those "insolent Persians" a lesson around A.D. 650, and it was high time to teach them another. These 1,300-year-old hatreds may be good for another 1,300 years. But surely the weakness of Iran after the revolution invited the attack.

The Danger of Disappointment and Oil Glut

Oil oversupply, and glutted markets, are also a source of instability. In 1978, markets were glutted and prices weak. The OPEC Secretary General warned that if OPEC exports stagnated there would be "political and economic disasters" in the OPEC nations because of revenue cutbacks and disappointed expectations.[2] Supply cutbacks to force prices up were therefore likely, and arrived soon after, as we will see.

In 1981, OPEC exports were down by roughly a third from the 1978 level. The "political and economic disasters" have been prevented, so far, by prices which in real terms are well over twice those of 1978. But expectations rise as rapidly as revenues. The price explosion of 1979 crystallized immediately into higher spending programs in the exporting nations. Even the very mild price decreases of 1980-81 have led to serious internal strains within these governments. Claimants for funds have struggled to shift the burden of cutbacks onto others. The inability to cut expenditures has paralyzed some of these countries' will to face market conditions and reduce prices, and they have lost heavily in sales and revenues. The spending of oil revenues generates a perceived need for even higher revenues. "[The] gains of oil-induced growth tend to increase rather than decrease the dependence. . .on the quantity and price of crude oil exports."[3]

Thus market glut is a political destabilizer. Higher prices are a temporary pacifier. But it is no longer clear that oil prices can be profitably raised. The point of unit elasticity, or decreasing marginal revenues, may or may not yet have been reached. It is certainly closer than in 1978. The odds are today against any price increase for the next year or two. Continuing inflation will therefore erode real prices and revenues. It is a sad paradox: weak prices make for political strife, loss of supply, and hence irregularly spurting prices.

[2] Ali Jaidah, quoted in *Petroleum Intelligence Weekly* (September 25, 1978). OPEC production that year was 31.5 mbd (including natural gas liquids); consumption was estimated at 2.4 mbd.

[3] Ali A. Attiga (Secretary-General of OPEC), "Economic Development of Oil Producing Countries," *OPEC Bulletin* 11 (November 1981): 11. The whole article deserves careful reading.

The Danger of Iran and Iraq Back on the Market

Cartel agreement on output cutbacks is difficult and divisive. It has been avoidable because the collapse of Iran and its war with Iraq has been a piece of great good luck for the cartel. If Iran and Iraq return to the market in large volumes, similar good luck will be contrived. The Persian Gulf war has shown how even small air and naval forces, however ineffectually used, can suppress oil loading for export, though not oil production. The Persian Gulf states will use force or the threat of force to contain excess supply.

A million barrels daily of output gained, or its loss prevented, is at current prices worth over $12 billion per year. The necessary hardware and personnel cost only a small fraction of the annual gain. That is an investment some can't refuse. But military actions are easier to start than to stop.

The Clumsy Cartel

As important as any shock is the market mechanism to which it happens. Between 1973–74 and 1979, the cartel fixed prices and let output adjust. Since late 1978, it has been trying to manage output to raise or maintain prices. That policy was recently reaffirmed.[4] Unfortunately, nobody can fine tune with coarse instruments. Years ago, the Texas Railroad Commission regulated output using accurate timely information on production, consumption, and inventories. Worldwide, these data are imprecise, and are months or years delayed. The cartel is forced to act in ignorance. Except when improbably lucky, they must overshoot or undershoot. But while they fear a glut, they will allow us to bear a shortage, and every buyer and seller knows it can happen anytime. Officials of the European Economic Community, after a swing around the Persian Gulf in June 1979, said that the Gulf nations are trying to maintain a small chronic shortage.[5] One of them accurately called it "brinkmanship," which some thought in terribly bad taste.[6]

The Iranian revolution did not produce the crisis. Consumption practically equalled production in the last quarter of 1978. In the first quarter of 1979, worldwide inventory drawdown was 5.5 million barrels daily, but this was a normal seasonal movement. A year earlier, amid glut, the drawdown was 5.1 mbd. (In the United States, crude stocks began to rise in late January, and by early March they actually exceeded the year-end level.) Moreover, some of the 1979 product inventory drawdown was apparent not real: a transfer into distributors' and consumers' stocks. After March 1979, production always exceeded consumption, yet prices continued to rise. Furthermore, there was at all times excess capacity of over 4 mbd.[7] There had been some spot price increases in the fall, based largely on the expectation of official price increases later, but nothing resembling panic until the deliberate Saudi cut on January 20, 1979, from over 10 mbd to 8 mbd. An apprehensive oilman had summed up the problem perfectly: it was one thing for the Saudis to cut back to maintain "a nice tight supply situation." But it was something else for them to "create a world crisis."[8] Prices exploded in February. When markets stabilized again, at higher prices, Saudi Arabia again cut output, in April–June, and prices spurted again. In June 1979, Sheikh Yamani said his government would not permit the price to go as high as $20.[9] But in January 1981, he called the price explosion of 1979–80 "another corrective action" like 1973–74, which indicates deliberate policy, not accident. Any time they try to overcome a glut and create "a nice tight supply situation," a crisis may be close.

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[4] *The Wall Street Journal*, 2 November 1981: 2.

[5] *Oil and Gas Journal* (9 July 1979): 35.

[6] Ibid.; and see also the July 16 (p. NL2) and July 23 (p. NL4) issues.

The Soviet Union is not an independent source of danger to oil supply. It would of course like to be a spoiler and deny us oil by exploiting local conflicts, making little ones into big ones.

Unfortunately, there is a powerful legend or stereotype of the energy-famished bear stretching his greedy paw toward the Persian Gulf because he cannot "satisfy his needs" with domestic supply. But "needs" should be spelled "nonsense." All the USSR can get out of occupying the Persian Gulf is cheaper energy. This is not its worth the cost, still less the risk of war. It is deplorable to see our Secretary of Defense repeat the legend that the Soviet Union is about to become an oil importer, particularly when his own Defense Intelligence Agency has concluded—and few will dispute today—that the Soviet Union will continue as a net hydrocarbon exporter throughout the 1980s.

II. SUPPLY CRISES ARE A DEMAND PHENOMENON

In every supply disruption, we can see in retrospect that the difference between the amount supplied and the amount consumed was very small. Inventories were more than adequate to cover it. But the amount *demanded* in the market place was much greater than what was to be *consumed*. The excess of demand is registered in the changes in the spot price.

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[7] Inventories: See DOE, *International Energy Indicators*. Capacity: *Petroleum Intelligence Weekly*. The CIA capacity measure is not used because it is not fully explained, and is in conflict with actual production data, as well as other evidence.

[8] *Petroleum Intelligence Weekly* (15 January 1979): 1.

[9] *New York Times*, 22 June 1979.

Recently Exxon Corporation had the courage to estimate worldwide inventories, including those past the primary distributors, at roughly 6 months' or 180 days' supply. Suppose that each holder tries to increase his stocks by a modest 10 percent within a 60-day period. Over that period, then, the amount demanded will be 30 percent larger.

Reason for Panic

The reason for the surge in demand and the desire to hoard is so familiar that we tend to overlook it. The value of any product is measured by the damage inflicted by not having it. (It is our old friend consumer surplus, Dr. Jekyll, suddenly becoming Mr. Hyde.) Refiners or distributors or consumers fearing physical dearth – actually running dry – will hold back all they can, and demand more than they intend to use. This additional demand is much greater than any expected or perceived shortfall.

Planning for supply disruptions is geared to loss of output, and tries to adjust to a smaller total physical flow by rearranging physical flows. Unfortunately, it is largely irrelevant to the real problem – the desire to maintain and increase inventories.

Spot Prices and "Mainstream" Prices

Most oil moves under contract or at prices based on contract. Since nobody can accurately predict sales, one usually has a small excess or deficit, absorbed in inventory changes. The spot market is the place where companies bring those temporary excess supplies and excess demands too large for inventory absorption. These excess amounts usually cancel, but not every day or every week. Consequently, there are usually small ups and downs in spot prices. Prices elsewhere do not respond immediately to changes in the spot markets. In normal times it is to everyone's interest that "mainstream markets" remain sluggish.

But useful habits are sometimes harmful. Once a shortage begins, spot prices move up, but not prices in mainstream markets, nor consumer prices, so there is no restraint on demand. Anyone holding an inventory, and seeing spot prices move up radically, has good reason to expect that mainstream prices will soon be higher. Thus the hope of gain is added to the fear of loss through dearth. Everyone hangs on all the harder to oil, to build or retain stocks.

Spot Prices, Government Selling Prices, and Restriction

In 1979 the exporting nations soon began to cancel contracts or to reduce deliveries in order to sell into the higher-priced spot markets.

Only the presence of excess demand makes this diversion profitable, and also permits sellers to impose and enforce all kinds of restraints, like promising to use the oil only in their own country and not transship; or to use it only in their own refinery and not sell it to anyone, and so on. Private buyers are willing, and governments are downright eager, to be seen accepting constraints. It shows their power to keep their own nationals supplied at the expense of others. They are doing something, not just standing there.

Thus excess demand not only raises the market-clearing price, but also serves to Balkanize the market and thus make it inefficient. Buyers find their customary suppliers suddenly disappearing or unable to supply them, and this feeds panic. The flexibility of the system is lost. Those who have agreed to restriction on destination or use explain that much as they would love to help, they cannot ship to others because they have given their word not to.

The United States in 1979 as World Paradigm

In this respect, the paradigm is the United States under allocation in 1979. Every time that any segment of the market was guaranteed its "needs," they would take all they consumed and more, thus making the shortage worse for everybody else. When farmers were given their "needs" of diesel oil, it soon was necessary to guarantee truckers their "needs" also. Governors of the various states received gasoline set-asides that reduced the supply available to everybody else. I will not rehearse the all-too-familiar story of how the attempt to allocate products, area by area, month by month, generated worse shortages. But the United States in 1979 is the model for the international market, given excess demand overall and even transient full supply to some. The excess demand is funneled into the spot market, driving prices there ever higher and making buyers bid even more frenziedly.

The almost unquestioned major premise among governments that in an emergency there has got to be a "fair allocation at reasonable prices" is possibly the greatest single aggravating force in making disruptions worse then they need to be.

The Persian Gulf War of 1980: A Non-Crisis

Let us consider the latest history lesson, the outbreak of the Persian Gulf war in late 1980. The loss of supply was greater than the loss from the Iranian revolution. But spot prices rose only briefly and then came down. The reasons are not in doubt. First, the OPEC nations cancelled their "gentlemen's agreement" for a 10-percent production cut, between 2.5 and 3 mbd. Second, inventories in the hands of private parties and governments were considerably higher than two years earlier. Finally, spot prices had lost their sting, because there was less reason to expect high contract prices and consumer prices. Many perceived that Saudi Arabia, having engineered a rise from $12 to $32 (now $34), thought it was enough. The higher spot price of October 1980 was perceived as being a temporary upward fluctuation, and did not lead to a grab for inventories and a continued bidding up.

III. COPING WITH INSECURITY

The situation is alleviated to some degree by the developments in world markets. Non-Communist consumption in 1981 was actually below its 1973 level. In that year, OPEC exports accounted for about two-thirds of non-Communist consumption, and in 1981 for less than 45 percent. I expect the export decline to continue, as oil consumption stagnates or declines and non-OPEC production creeps up. Yet, this tendency to lower OPEC exports was well under way in 1979, and it did not spare us a worse convulsion than in 1973. There is no prospect that supply out of the unstable areas will cease to be of great importance to the consuming countries, and therefore no prospect of eliminating insecurity.

The Non-Solutions

"Energy independence" was always a delusion. Even if by some miracle U.S. imports went to zero, a reduction in worldwide output would be a reduction in supply everywhere. A shock to the world economy is an immediate shock to us. The same delusive hope of insulating one's nation from the world makes the Europeans and Japanese envious of our mythical "special relationship" with Saudi Arabia, as they were of our "special relationship" with Iran. It leads them into shabby deals and maneuvers that have done them no good.

We will continue to hear arguments for some kind of agreement with the oil-exporting countries, whereby they promise us "reasonably assured supplies" in return for higher prices, "access" to technology, etc., etc. The OPEC long-term strategy committee endorsed such as agreement and will continue to emphasize it. During the 1980 presidential campaign, it was advocated by Mr. Kennedy on the left, Mr. Connally on the right, and Mr. Carter somewhere in between. Doubtless it will be high on the agenda of any "global negotiations." We must at all costs avoid any such agreement. It is impossible to keep the oil exporters, who are sovereign monopolists, to their word. Anyone who doubts this should look at the long dreary list of broken promises since 1971. The latest was mentioned earlier: the Saudis' 1979 assurance of a price below $20.

Private Stockpiling

The only defense or mitigation of a supply crisis lies in stockpiling. I think it is unreasonable to expect private stockpiling to do the job. Preventing excess demand and upward-spiraling prices is a public good. A speculator tries to buy cheap to make a profit by selling dear in the future. The private sector is helpful to the extent that speculators buy during period of slack, in the hope of making a killing during shortages. We should put no obstacle in the way of those who wish to do so. Some of course speculate the other way, i.e., they cut back inventories to gamble that the government will seize others' stocks to turn over to them at "fair and reasonable prices." The law that expired in 1981 expressly forbade the accumulation of inventories in excess of one's own "needs." It was a good example to avoid.

Nevertheless, although private inventory accumulation should not be discouraged, it should not be relied on, because the risks are too great to attract speculators. Consider a hypothetical investor who might have bought Saudi Arab Light oil for speculation in June 1974, when the new order emerged pretty clearly. He would have lost, in real terms, over the next four years. Had he held on another year, he would have had 2.5 times, real, his original investment (reckoning a constant inflation rate of 10 percent per year). This would be a five-year real return of 20 percent per year. But had he held the barrel another two years, to mid-1981, the seven-year real return would have been down to 7 percent per year. Thus the investment would be a highly risky one, and correct timing would make all the difference.

Let us give the standard Capital Asset Pricing Model its due. The wide year-to-year fluctuations would be essentially independent of fluctuations in all other assets except gold and other such mirrors for panic. Thus to an investor with a diversified portfolio, the investment in oil might seem non-risky, once its diversification effect was allowed for. On past performance, oil speculation might look like a good bet, but experience does not confirm the theory.

Since late 1980, once it appeared that the Iran–Iraq war was not going to precipitate another crisis, the oil industry has been liquidating inventory. The usual, and doubtless valid, explanation is current high interest rates, roughly 6 to 10 percent, real. But then the net expected return on oil stocks, including the diversification effect, must be lower. Oil appears not worth holding for speculation, only for normal business needs, though the "normal" will probably be higher than in the past, and the growing flexibility of refining facilities is a growing stock of services with a similar effect.

There are a number of places in the world that conveniently bring together nearness to tidewater and a permissive tax or regulatory authority. Storing oil in large amounts in these pleasant climates would be a natural way of speculation, but this has not been done so far.

I argued earlier that wherever the ultimate ceiling to crude oil prices might be, we are obviously much closer than we were in 1974 or even 1978. Hence the future will probably not see so great an increase as the past. The experience of the last seven years is an upward-biased predictor. It is more than possible that the maximum has even been reached or exceeded. But even if one takes seriously some confident predictions that the real price of oil will be $100 per barrel at the end of the century, which I do not believe, this amounts after all to only 6 percent per year, a return that seems insufficient to attract private investment.

IV. THE STRATEGIC PETROLEUM RESERVE

A public stockpile is our only means of defense. The Strategic Petroleum Reserve (SPR) was established by law at the end of 1975. For three years there was bad luck, bad management, and little accumulation. In late 1978, the Carter administration made an agreement with Saudi Arabia, whereby it promised to stop buying for the SPR in return for a promise that the Saudis would maintain a high rate of output. The Saudis broke their promise within two months, but we kept to ours for over two years, until Congress overrode President Carter and required that the fill be resumed. (Some would now like to deny the existence of this agreement, but they cannot explain away the public record. And if a congressional committee were to question the former President and his cabinet, there would be no doubt.) This was the latest proof of why we must avoid the "cooperation-dialogue-interdependence" trap.

The neglect of the SPR, and the irredeemable waste of time during which we should have been filling it, has arisen partly from lack of understanding, partly from misplaced economy, and partly from the strong opposition of the exporting countries, who have often denounced it. Their opposition to stockpiles, like their abhorrence of taxes and tariffs on oil, shows that they have a much better understanding of oil markets than we give them credit for.

Their most usual complaint is that a stockpile would permit us to bring down the price of crude oil. In a competitive market, this would be impossible. Accumulation of a stockpile would raise demand and price temporarily; its decumulation would lower the price, again temporarily. But in a noncompetitive market, small causes can have large effects. A temporary surplus, as we have repeatedly seen, is a grave embarrassment to the OPEC nations. When a price is set far above the competitive level, a temporary break could be permanent.

A large enough stockpile could therefore, in theory, disrupt the cartel and bring the price crashing down. In my opinion, a stockpile should not be used for this purpose, whatever the temptation.

Decision Rules for the SPR

The purpose of the stockpile is to quell panic and, if necessary, buy the time needed to react. I maintained earlier that supply disruptions were damaging primarily because of sudden increases in demand for hoarding. Trying to estimate the shortfall is nearly useless. The only reliable measure of market imbalance is the spot price.

The government should be the oil seller of last resort, just as a central bank is a lender of last resort. We ought to adopt Victorian financial wisdom for handling panics: lend freely and without limit, but charge all the traffic will bear. This is diametrically opposed to the current regime.

The IEA rule, for example, is that (some kind of) measures should be taken when the "shortfall" reaches 7 percent. During the last crisis, it never went that high, and nothing was done. Yet the price nearly tripled.

To trigger sales by some shortfall estimate is wrong because we will have only a very inaccurate idea of the shortfall until a long time afterward. Moreover, if the analysis of this paper is correct, the amount of the shortfall has little or nothing to do with the market disturbance. If traders fear a crisis, and demand large amounts for hoarding, a crisis is sure. Our problem is to avoid this demand surge. (In technical language, we are not concerned with the steepness of the shortrun demand curve when supply decreases; we are concerned with a large rightward shift in the short-run demand curve.)

The rate and timing of stockpile sales cannot be predetermined; it depends on how great the demand is for hoarding.

The rule that prices should be "reasonable" or somehow less than the traffic will bear, is bad policy. It discourages private stock building and encourages "short selling," i.e., lessening of inventories during normal or glut periods in the expectation that the government will ration or allocate oil at less than market prices during shortages.

Public reserve stocks should be used for prevention, not for cure. We should not try to guess at a shortfall, nor try to redirect oil shipments according to indefinable criteria that are sure to provoke disagreement and backbiting. All this amid an unseemly scramble for valuable pieces of paper–entitlements to buy at less than market prices. But if we can avoid or diminish the demand surge for hoarding, the spot market should not rise fast or far. As we have seen, in past crises, the actual deficit has been small, or nonexistent, and has not lasted long. Had there been no hoarding demand surge, prices would not have risen much, and there would not have been public panic that insisted on rationing and/or price control, thereby making things much worse than they needed to be.

Our suggested rule could hardly be more simple. The SPR "window" should be open for sale at all times, to sell any amount of crude oil. The buyer would pay the highest price being charged anywhere in the world on the day of purchase or on the day of delivery, whichever was higher, *plus* the cost of a year's storage.

For anyone fearing dearth, the price is a bargain. Nobody else would want to buy. Anyone tempted to buy for speculation must consider that the spot price incorporates expected increases as perceived in the marketplace. Therefore he had better have some pretty good reasons for pitting his own judgment against the market, and paying top dollar for the privilege of doing so. With no demand for hoarding, we would have quiet spot markets and a repeat of the 1980 non-crisis, unless the loss of supply were to far exceed anything known up to now.

In the United States, inventories actually rose by 62 million barrels in the last quarter of 1978. In the first quarter of 1979, they declined by 132 million barrels, which was less than the decline a year earlier, and only 10 percent of total private inventories. Normal commercial stocks can easily accommodate such a change. If nobody had feared dearth, there would have been no problem.

We may now consider how big a stockpile we need. One approach is to figure the macro-effects of given supply disruptions. Such calculations are difficult, and involve many unprovable assumptions. My suggestion would be that we take the worst foreseeable case: a complete loss of supply from the Persian Gulf, which today is about one-third of non-

Communist, non-OPEC consumption. This is a worse case than, say, the blockage of the Straits of Hormuz, since much of the oil produced in the Persian Gulf can be shipped overland by pipelines. It is from six to seven times as great as the losses suffered in 1973 and 1979.

Suppose that prices are left unimpeded to work out the distribution among nations. Then the total loss of one-third of the total supply would be approximately the same everywhere. That happens to be the share of oil imports today in the United States, so it is a handy assumption that we lose all imports.

The National Petroleum Council recently estimated that various measures for fuel conservation and extra output would provide between 2.3 and 2.8 million barrels daily. It would be more prudent to assume only 1.5 million, which would bring the drawdown of the SPR, assuming no private drawdowns, to about 4 mbd. A six-month stockpile would then be 750 million barrels, and indeed most responsible estimates have been in the range between 500 million and 1 billion. The SPR would last longer than six months. First, private inventories can be drawn down substantially. Second, consumption would be restricted further by the higher prices, although it is hard to say how much.

Deliberate embargoes would become impossible with a substantial SPR, since this country would be in a position to take all sorts of counteraction, which the embargoing nations would be anxious not to see. The fear and anxiety of the wheels grinding to a stop in consuming countries, massive unemployment and immobilizing of the labor force, and so on, would no longer put the pistol to this nation's head.

It is difficult to conceive of an emergency lasting longer than six months. The worst case would obviously be one or more Persian Gulf countries starting a "little war" that would escalate into a larger one. Such an eventuality is of course the reason for the current attempt to build up a rapid deployment force.

Good use of the SPR would prevent panic and buy time. To use it properly, we urgently need air, naval, and ground forces available at the Persian Gulf within hours and days rather than months and years. It would shield the Soviet Union from the temptation to try an adventure. Unfortunately, the United States is in the same difficult position as the leading member of a cartel. What the leader does, makes a big difference. A minor participant can expect others to cover for him, because failure to do so would only make matters worse for them. The leading member cannot hope for any such consideration. What he does, or fails to do, is decisive, and he must assume his responsibilities.

The governments of the various consuming countries are doing very little to help the United States defend the Persian Gulf, even though their economies would be injured even more by a supply crisis than would ours. They know that the United States cannot afford, in its own interest, to neglect the responsibility of protecting and controlling the Persian Gulf area. It is an unhealthy condition.

V. MANAGING A PRICE-ORIENTED POLICY

The SPR today is less than a third of what it should be, the fill rate appears to be decreasing, and it is not clear what the Congress and the Chief Executive have in mind for it. Yet it remains our only hope for avoiding the panic, and mitigating the upward wild spiral in prices, which will follow when the next supply disruption comes, as come it will.

In what follows, I simply assume that the will and good sense are there to keep filling it rapidly, and pass the problems raised in quick review.

As I indicated earlier, supply disruptions are serious because of the surge in demand, which should be met by building an SPR and depleting it at current spot prices. Those prices will be lower than if we were trying to manage or allocate supply. But this in turn requires some measures meant to affect prices, although they are not to be directly fixed.

Paying for the Strategic Petroleum Reserve

If we agree that oil imports are insecure, and that an SPR would make us tolerably secure, it follows that every barrel imported carries with it the cost of maintaining the reserve. That cost should be recognized and made explicit. At current levels of imports, I would reckon it roughly at $3 per barrel.[10] But the precise amount in unimportant; the principle is, imported oil costs the economy more. It is self-deception to pretend otherwise, and bad social policy to subsidize imports by covering part of the true cost out of the Treasury.

A tariff on oil imports would also provide much-needed revenue in the near future, when the deficits threaten to surpass anything previously known. (With imports in the neighborhood of 5.5 million barrels daily, and a landed cost of about $35, annual revenues would be $7 billion.)

If the domestic price of oil were to rise by the amount of the tariff, which is likely but not certain, Windfall Profits Tax receipts would also increase. We refrain from making any estimates, for the problem is

[10] Reckoning the value of the oil and the cost of storage, a barrel would cost about $40, a stockpile of 750 million barrels some $30 billion. The discount rate would be about 20 percent, nominal not real because we cannot be sure that the value of the oil will rise with the general inflation rate. Dividing $6 billion annual cost by about 2 billion annual imports (5.5 million barrels daily) gives the cost per barrel.

swallowed up in a bigger one – what to do after the crisis happens and spot prices rise.

There should be no attempt to allocate supplies, either inside the United States or internationally. During a disruption, the principal need is to move relatively small amounts of crude around the world as quickly as possible to where they are needed most. This is best left to private enterprise bent on making money out of the redirection.

With the huge exception of the SPR, therefore, my suggestion is to rely on private markets to get the crude oil and products moving, and to make the best of the limited supply.

Private windfall gains are, in general, best captured through the income tax. The misnamed Windfall Profits Tax is really an excise tax, and much can be said against it as a permanent measure, but during a disruption it will capture immediately a large part of the disruption gains. The speed is worth the inefficiency. In addition, we need a disruption tariff, over and above the permanent security tariff mentioned earlier. We can combine the two needs by a single tariff *ad valorem*, with a sliding scale; for example, at a $34 price, it would be 10 percent, while at a $50 price it would be 20 percent, or $10.

Some of the tax will fall not on consumers but on the producing nations, who have long understood that the higher the excise taxes levied on oil products in the consuming countries, the less is left for them. An *ad valorem* tariff could raise the consumer price toward or even past the point of unit elasticity, where further increases would actually reduce sales. The exporting nations would be forced to reduce prices, as a lesser evil. Their understanding would be helped because the *ad valorem* tariff is in effect a matching grant: anyone selling at a lower price pays a lower tax. Anyone trying to raise prices will be doubly penalized. At the limit, importing countries could divert all oil revenues into their own economies.[11]

With large revenues coming into the Treasury, the problem will be to get them back into the economy, and quickly. Rough justice is the best we can hope for. The most obvious channel is by an immediate reduction in Social Security deductions. Income tax refunds and rebates are unfortunately slow. Some people will get too much. Our concern ought to be not with those who do not get "enough," but with that fraction who cannot bear it. To those at the poverty level, sharply higher oil prices are a burden because of reduced total real income. They need additional dollars, not special allocations.

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[11] For proof of these propositions, see my "Constraints on the World Oil Monopoly Prices," *Resources and Energy* (1978).

CONCLUSIONS

Supply disruptions are likely. If we store oil, and let prices distribute the oil, we can prevent disruption from becoming a crisis. We should influence prices by tariffs, partly because we can pass some of the burden back to the exporting nations. If they treat this as confrontation, so be it; but it is unlikely. Recall that after minatory language about how we "must not" stockpile, when we resumed it in October 1980, the exporting nations actually increased output.

The theme of this Annual Meeting is "Energy in the Reagan Era." The Reagan administration appears to have no policy for coping with the supply disruptions. Talk of "the market" only delays use of market mechanisms.

When the next crisis suddenly comes and prices rise, huge amounts of money will be transferred from the pockets of consumers to private parties and to governments. If we remain unprepared, there will be resentment, turmoil, and hurried schemes for rationing, allocation, and price control. We have twice suffered these convulsions, which is twice too many.

[From the New York Times, Feb. 27, 1983]

BEWARE OF ANOTHER OIL PRICE EXPLOSION

To the Editor:

It now seems possible that Saudi Arabia agreed with the Aramco companies, on Jan. 2/3, to lower their price, through some expedients which we will duly learn. To call the rebate an exploration discount would not be credible. That discount was set in 1976 at six cents, a fair enough estimate of what an additional barrel of oil in the ground is worth to the Saudis, who have more oil than they will produce in this century, or perhaps ever.

Prices will fluctuate. On the down side, the competitive floor must be well below $10. But such a price seems very unlikely. If the cartel were really to "collapse" today, strenuous efforts would begin tomorrow to restore it.

A look far down at the floor may concentrate minds wonderfully among exporting nations, expecially when it becomes evident that Saudi threats to cut the price have not been an empty bluff. The ranks break and reform, and the distinction between non-conformist members of OPEC—Iran, Libya, Ecuador and now Nigeria—and nonmembers, such as Mexico, Britain and Norway, is becoming unimportant.

The current disarray results from huge excess capacity and from the difficulty of arranging for an output cutback. In any cartel, a member who is much the largest tends to carry much more than his share of the burden. Each smaller member can evade his share of the cutback, or whatever else is called for, knowing that the others will in their own interest cover for him.

But the buck stops with the largest member; if he fails to cooperate, the group collapses. Thus, the cartel leader tends to lose market share to the smaller members, rather than let the cartel fail and competition take over.

The same rule holds for other kinds of coalitions. The United States defends the Persian Gulf practically alone, although the loss of oil supply would hurt our European and Asian allies even more than us. But they evade the burden of defense because we dare not evade it.

Saudi Arabia has resisted the tendency, long and hard. Had there been any truth in the official legend that they preferred to keep their oil in the ground, and were making a "sacrifice" producing more than three million barrels daily, the oversupply of the last few years would have come as a great relief to them. But that unlikely story is on the shelf for now.

The Saudis will not continue to give ground without assurance that others will keep their output within limits; they seek to make assurance doubly sure by fixing price differentials such that others will not take away markets by offering better bargains.

A mild economic upturn, which seems to be starting now, may be enough to hold the price level, if everyone is willing to accept the sales volume he had in the recent past and to tolerate small gains or losses. Indeed, a moderate revival, plus some restocking by oil refiners and consumers, could produce a price explosion like that of 1979. There was no shortage then. Consumption hardly exceeded production, and commercial inventories could easily have made up the difference, if any.

But the OPEC nations were—rightly—obsessed by the need to do away with the glut, which had oppressed them in 1978, and they took in the slack so fast as to create an intolerable strain.

Twice the Saudis cut production—in January 1979 and again in April. Panic did the rest, as the trade bid the earth for any scrap of oil in sight. As one oilman put it, the Saudis aimed only at "a nice tight supply situation" but they made "a world crisis."

That is their aim today, and with a little bit of luck—good or bad, depending on where you sit—we can get the crisis anytime.

A stable price, or a stable rate of increase or decrease, is about the last thing we should expect. At such a time, it makes no sense to slow down the additions to the Strategic Petroleum Reserve.—M. A. Adelman, Cambridge, Mass., Feb. 21, 1983.

World Oil Prices and Economic Growth In the 1980s

*Henry D. Jacoby and James L. Paddock**

I. INTRODUCTION

The world oil market is a forecaster's nightmare: seldom have so many knowledgeable observers been so wrong so often. Prior to 1973, few foresaw the magnitude of the price jump that was possible under disrupted conditions, or predicted the years of relative stability that followed. The Iranian revolution brought a similar surprise. On the other hand, in the fall of 1980 came the Iran–Iraq war; again a major price shock seemed at hand. Experts are still arguing about why it did not occur.

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*Sloan School of Management and the Energy Laboratory, Massachusetts Institute of Technology, Cambridge, Mass. 02139.

Forecasting is no easier today. In a world of slack demand and huge excess capacity, prices are falling. Yet a disruption could send the oil price skyrocketing again. Still, it is important to have as clear a view as possible of likely future conditions in oil markets. Critical plans and investments need to be decided, and many of these depend on forecasts of future oil prices. In this paper we present a method for combining analytical models and expert judgment in order to explore this future.

It should be emphasized that we do not attempt a single price forecast, or even a range of forecasts or scenarios. The uncertainties are so great and our ignorance of key relationships so overwhelming that a specific forecast, even with bands of error, tends to give a false impression of accuracy. Rather, we take the approach of ruling out certain combinations of possible future events that we can plausibly argue are "unlikely." The procedure defines a window into the future that consists of the remaining set of not-unlikely events, and this window summarizes our knowledge about the world oil price and associated conditions in the world economy over the decade.

Several factors come into play in defining such a window. The oil market must clear at each point along the way: consumption cannot exceed the quantity of oil made available to the world market. The effects of oil price on world economic growth must be accounted for: under some oil price conditions, healthy growth probably cannot be sustained. And, of course, there is the behavior of the OPEC leaders themselves. What follows, then, is a set of calculations, some rather mechanical, which bring these various factors together to rule out the unlikely combinations and identify the window, or envelope, of feasible paths to the future.

II. OIL DEMAND AND SUPPLY

To carry out the analysis, we need to be able to forecast the responses of oil demand and supply to conditions in the oil market. For this purpose we use a set of studies, estimates, and model-construction activities carried out over several years by the World Oil Project at the M.I.T. Energy Laboratory.[1] The credibility of our results ultimately depends on the performance of this apparatus, so we turn first to a brief description of how it is put together.

Oil Demand

There are many influences on the demand for oil, but the major ones are the oil price, P, and the level of economic activity, which may be measured in

[1] For more detailed discussion of these models and the results discussed here, see Jacoby and Paddock (1981).

terms of gross domestic product, GDP. In recent years there have been many analyses of the demand for oil. The analytic methods used range from econometrics (Pindyck, 1979) to engineering systems evaluation, with various hybrids in between (EMF No. 4 Working Group, 1981). Most studies estimate a relationship of the form

$$D = D(P, GDP) \tag{1}$$

That is, energy demand, D, is specified as a function of price (and perhaps other factors), given values of GDP.

As the pain of recent years will bear evidence, however, the pace of economic activity is affected importantly by oil prices. What really is needed is a function of the form

$$D = D(P, GDP[P]) \tag{2}$$

Unfortunately, only recently has there been much work on the relationship GDP[P]. Some studies (e.g., Hudson and Jorgenson, 1978) explore the influence of oil price as a real phenomenon. They analyze the process by which real resources are reallocated or pulled out of the economy as oil prices rise. These studies show a dampening effect of rising oil prices on economic activity in the long run, but the influence is small.

Other researchers have begun to study the short-term effects of oil price shocks (Mork and Hall, 1980; Hall and Pindyck, 1980; Pindyck, 1980; Nordhaus, 1980). They attempt to understand the effect of energy prices on inflation, and the GDP losses that result when domestic markets (particularly labor markets) and macroeconomic policies do not adjust properly and quickly to changing energy prices. These studies show the relationship between P and GDP to be very complex—working through the mechanism of inflationary expectations and its effect on labor markets, investment, and consumer behavior. Also, because there are effects on inflation and balance of payments, variations in P call forth government policy responses that further affect GDP. Many of these policies turn out to be contradictory or self-defeating, and they can serve to depress GDP further as well as impede adjustment to a new GDP growth path.

Thus the process of adjustment to price shocks is inherently difficult to analyze, depending heavily as it does on government reactions in the form of monetary, fiscal, and trade policies. And although there is a growing body of research, there is as yet little consensus on the empirical estimates of these effects. In such a circumstance, our response has been to organize the analysis so as to allow for a goodly dose of judgment, as well as available analytical results, in the interpretation of the influence of P on GDP.

The MIT simulation model is used to compute forecasts of energy demand, by sector and fuel type, in each of the OECD countries and to aggregate their petroleum product demands with crude oil demands from the rest of the world (excluding the centrally planned economies).[2] The simulation model is essentially of the form of equation (1), and it makes use of econometric work done by Pindyck (1979) as part of the M.I.T. World Oil Project.

Country-specific price elasticities (both own and cross) and income elasticities, by sector and fuel type, are incorporated in the model. These parameters vary significantly across countries, as shown in Table 1. A complete listing is presented in Carson, Christian, and Ward (1981) and Pindyck (1979).

The elasticities in Table 1 are measured at the point of consumption, and are for the 11 largest OECD countries, which were modeled in sectoral detail. When combined with simpler estimates of oil demand in other parts of the world, the model demonstrates an overall long-term worldwide price elasticity, measured at the Persian Gulf at a $34 price level (in 1982 dollars), of approximately −0.54. The accompanying long-term income elasticity is 0.90. To produce period-by-period estimates of demand, price changes are smoothed by a Koyck lag with parameters set (with a heavy dose of judgment) to reflect the speed of adjustment in different sectors.

Oil Supply

The world supply of oil has received little formal analysis, even since 1973. While there is a considerable literature on the theoretical determinants of oil production, few empirical analyses (available to the public) have been conducted for important areas of the world other than the United States, Canada, and the North Sea. Severely restricted data availability is a prime culprit.

The supply models that are open to scrutiny are, for the most part, judgmental extrapolations of historical production, subject to some assumed potential reserve base. The usual approach is to combine geological and engineering information in an optimizing framework, with attention to the three phrases of the supply process: exploration and dis-

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[2] For a more detailed description of this model, see Carson, Christian, and Ward (1981).

Table 1. Ranges of Long-Run Own-Price and Income Elasticities among Selected OECD Countries, by Fuel Type and Sector

	Residential		*Industrial*		*Transportation*	
Fuel Type	*Own-Price*	*Income*	*Own-Price*	*Income*	*Own-Price*	*Income*
Motor gasoline	n.a.	n.a.	n.a.	n.a.	−1.77 to −1.13	0.79 to 0.99
Diesel fuel	n.a.	n.a.	n.a.	n.a.	−1.10 to −0.61	0.78 to 0.93
Heavy oil (Nos. 4 and 6)	n.a.	n.a.	−1.17 to −0.30	1.00	n.a.	n.a.
Heating oil (No. 2)	−1.38 to −1.10	1.00	n.a.	n.a.	n.a.	n.a.
Coal	−1.12 to −1.00	1.00	−2.24 to −1.29	1.00	n.a.	n.a.
Natural gas	−2.09 to −1.28	1.00	−2.34 to −0.41	1.00	n.a.	n.a.

n.a. = not applicable

covery of fields, development of reserves, and production. Profit maximization is the typical objective function, generally with implicit constraints introduced in the form of engineering process submodels of drilling and reserve development.[3]

The supply side of the MIT-WOP model is of the same general form as these other analyses. It provides estimates of the production capacity, C, for all oil-producing countries excluding the centrally planned economies, with an onshore/offshore breakdown where appropriate.[4] It is an inertial process–type model, which combines geological and petroleum engineering data with an economic analysis, with features designed to work around some of the more severe data restrictions.

Supply–Demand Balance

The supply and demand models have been combined into an integration framework for simulation of market balances. The model receives exogenous vectors of P_t and GDP_t and special production capacity constraints,[5] and it computes values of overall capacity and demand, C_t and D_t. There is an adjustment procedure to override the exogenous values of P_t and GDP_t if necessary to make markets clear—that is, to ensure that D_t does not exceed C_t.

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[3] See for example, EMF No. 6 Working Group (1981) and EIA (various years). Rarely do these studies incorporate other influences on supply, such as financial factors. In some producing countries this omission can be very damaging. In the mid-1970s, Mexico used increasing oil development as a lever to obtain international debt refinancing and to support the peso. In the late 1970s both Mexico and Norway keyed oil development to revenue targets.

[4] The model implements an estimation method and analysis developed in Adelman and Paddock (1980), Adelman and Jacoby (1979), and Adelman and Ward (1980). It is documented in Ward (1981) and in Carson, Christian, and Ward (1981).

Even if markets clear, of course, it is possible to have a condition where $C_t > D_t$, since C is capacity to produce rather than actual production. Indeed, such an excess capacity is the common state of the OPEC cartel. The analysis assumes the cartel core[6] acts to maintain the price by dividing the residual demand among themselves to clear the market.

III. THE OIL MARKET WINDOW IN 1990

With this set of models, we can proceed to delineate those combinations of oil price and economic performance that seem unlikely to occur between now and the year 1990, thereby constructing the "window" of events that are not unlikely. There is no attempt to carry the formal analysis beyond 1990, largely because of limitations of the data and models we are using. For many steps of the argument, this time horizon is perfectly satisfactory: the relevant phenomena actually occur within the decade. When we consider the behavior of OPEC suppliers, however, the focus on the 1980s alone leaves out important information. Oil exporters are concerned with prices and demand in the longer term, and with the ways that behavior in the 1980s may affect that future. When we reach that point in the analysis, we first will analyze events from the viewpoint of the 1980s alone—then explore how the results may be shifted by longer-term considerations.

Of course, where the world ends up in 1990 depends on the number and severity of any disruptions along the way. Many circumstances could lead to oil price shocks and extreme deviations in economic performance, and one cannot contemplate analyzing them in any detail. For our numerical calculations, therefore, we begin with a smoothly changing world. The analysis assumes a 1982 world oil price P_t (in mid-1982 dollars) of $34 per barrel, and considers alternative paths of exponential growth of this price.

[5] Alternative assumptions about Saudi Arabia are made, as noted below. Iranian facilities have suffered physical damage and deterioration as a result of the revolution and war. Kuwait has imposed production ceilings, and apparently is allowing previous capacity to deteriorate. In the calculations Kuwait is held to 1.5 mbd throughout the decade, and Iran is assumed to be able to produce no more than 3.0 mbd from 1982 to 1985, and 4.0 mbd from 1985 to 1990. Iraq also has suffered damage to oil facilities, but it appears that they can be repaired within a few years after cessation of hostilities, which we assume will take place in the 1983–1985 period.

[6] The core consists of Saudi Arabia, Kuwait, the Neutral Zone, the United Arab Emirates, Bahrain (although not an official OPEC member), Libya, and Venezuela. All other producers, inside OPEC and out, are assumed to be price takers.

Similarly, we treat the change in gross domestic product, GDP_t, as a smooth exponential process over the period of analysis. After carrying out the calculations based on these simple assumptions, we ask what the results might look like if the price change came not smoothly but in a single shock, say, in 1984.[7]

Oil Prices and Market Clearing

In defining the window in 1990, the thing we know most surely is that oil markets must clear all along the way; demand cannot exceed capacity. Therefore we begin by performing a set of calculations to determine which sets of price/growth scenarios lead to market clearing and which do not. Of course, figures for "capacity" are approximate and may vary with seasons and the condition of reservoirs and equipment; similarly, demand may vary due to seasonal factors, weather, and stockholding behavior. A stable market clearing price really implies some slack in the system. In the calculations shown here, that slack is maintained at 2 mbd, which is roughly 10 percent of OPEC exports. The resultant market clearing condition is

$$C_t - D(P_t, GDP_t) \geq 2 \quad \text{for all } t \tag{3}$$

The conditions of oil price and economic growth over the decade can be summarized in a set of vectors (P_t, GDP_t), where, for the time being, both price and growth are assumed to move at exponential rates. Some of these vector pairs do not satisfy constraint (3), and therefore those price and growth conditions are judged "unlikely" to occur. The sets of (P_t, GDP_t) that violate (3) are identified by making multiple runs of the simulation model laid out above. With a manageable number of calculations we can define a boundary between sets of (P_t, GDP_t) that satisfy (3) and those that do not, and these results define the lower sill on our window in 1990.

Figure 1 shows the space in which the window will be sketched. The vertical axis is the 1990 oil price in constant 1982 dollars. Also shown is the implied constant annual percentage growth rate in real prices, taking $34 in 1982 as the base.

The horizontal axis shows varying levels of GDP growth, with the United States used as an example. At the rightmost extreme (at the intersection with the vertical axis) is the "base" GDP growth rate, and the horizontal scale moving left indicates (lower) growth rates that may

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[7] The analysis does not deal with the massive change in the oil market that might result from war or revolution on the Arabian Peninsula. There are no credible models of what would happen to oil prices, economic activity, international payments, or international political stability in such an event.

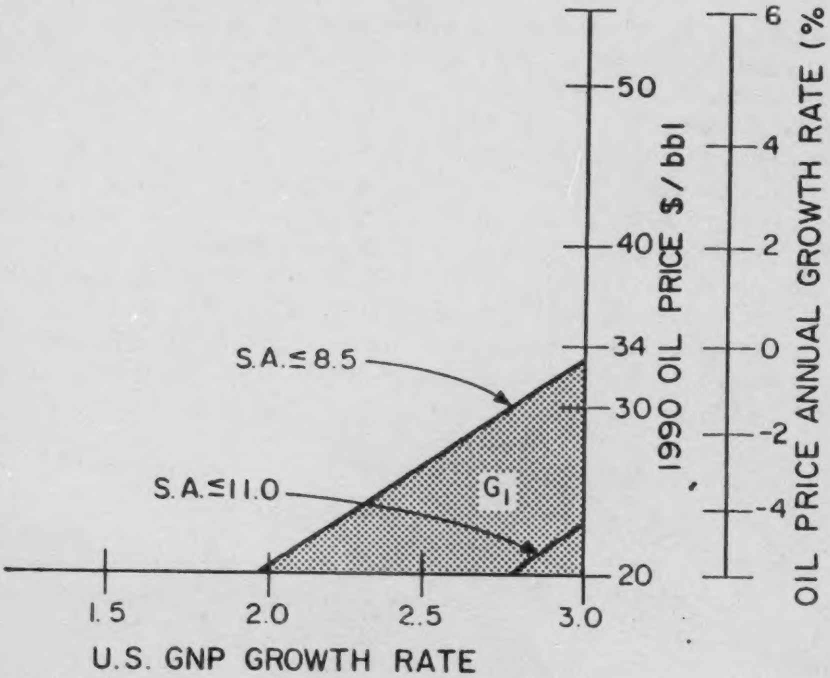

Figure 1. Oil price and GDP growth (1982 dollars): the requirement of market clearing.

actually be realized over the decade.[8] The growth of all countries is assumed to move up and down in proportion, and so the U.S. values in Figure 1 are also a representation of what is happening to the growth rates of all countries.

The line labeled "S.A. ≤ 8.5" represents the boundary of the feasible pairs of (P_t, GDP_t) under the assumption that Saudi Arabia will not produce more than 8.5 mbd.[9] The shaded area in the figure indicates the set of (P_t, GDP_t) pairs that are judged "unlikely" because, by the estimates of our model, markets would not clear. (Points in the shaded area are not impossible, for our demand and supply models may be in error.) The area to the upper-left of the line S.A. ≤ 8.5 is then the set of price-growth circumstances that cannot be judged unlikely simply because of a need to clear the oil market.[10]

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[8] The base GDP growth rates in this calculation are 5.0 percent for Japan, 3.0 percent for the United States and France, 3.5 percent for Canada, 4.0 percent for the Federal Republic of Germany, 2.5 percent for the U.K., and 3.2 percent for the rest of Western Europe. The equivalent growth rates for developing countries range from 3.0 percent to 5.0 percent; the rate for oil exporters is set at 6.0 percent.

[9] Note again that the line S.A. ≤ 8.5 is *not* a causal or functional relationship whereby price depends on GDP or vice versa. The line merely plots the boundary between those combinations (P_t, GDP_t) that clear markets and those that do not. The boundary slopes as it does because at higher GDP growth rates a higher rate of price increase is needed to offset the income effect.

Since we are using the language of "sets" to define the pairs of vectors (P_t, GDP_t), the shaded area, now ruled unlikely with an 8.5-mbd Saudi limit, is denoted as the set G_1. Ultimately, the price/growth window will show what is left when all the sets of unlikely events have been ruled out.

Figure 1 also shows another line, which locates the boundary of G_1 should the Saudi production limit be set at 11.0 mbd, which is the capacity now reportedly in place. This line is closer to the origin because, with more oil available, it becomes possible to clear markets with higher rates of economic activity and/or lower oil prices.

Oil Prices and Feasible Economic Growth

A second set of limits on likely combinations of (P, GDP) is imposed by the fact that GDP itself is a function of price. In terms of our analysis, there is a set $G_2 = f(P, GDP[P])$, which is unlikely for reasons of the depressing effects of energy price increases on economic growth. Even though, as discussed above, there is a growing body of analysis of future world GDP growth and the influence of oil price on it, we have as yet no formal model that will support a calculation of the boundaries of G_2. Therefore we construct an exercise that will allow the use of as much formal analysis as exists, and permit the easy introduction of judgment.[11]

The approach is illustrated in Figure 2, which consists of the same price-growth space as Figure 1. Look at point A in Figure 2, for example, and ask, "Is it likely that GDP growth can be sustained at 90 percent of the base levels if real oil prices are rising at 2 percent per year?" If the answer to that question is "no," or "not very likely," then point A falls into the region G_2. The same question could be asked about point B: "Is 75 percent of base growth rates likely while oil prices remain constant?" Here the response may be "I see no reason why not." Or, in our terms, point B is "not unlikely." By a sequence of such questions—with responses perhaps aided by formal analysis of the world growth process—the boundary, labeled X in Figure 2, can be located, and the upper region G_2 of unlikely combinations defined.

Thus, Figure 2 shows our judgment of the upper end of expected economic performance. Our impression is that the base growth rates are

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[10] Actually, Saudi Arabia was above 8.5 mbd at some points in 1980 and 1981. Our model does not account for the short-term conditions associated with the Iran–Iraq war.

[11] The 1983 GDP levels are set equal to values forecast by the OECD in December 1982.

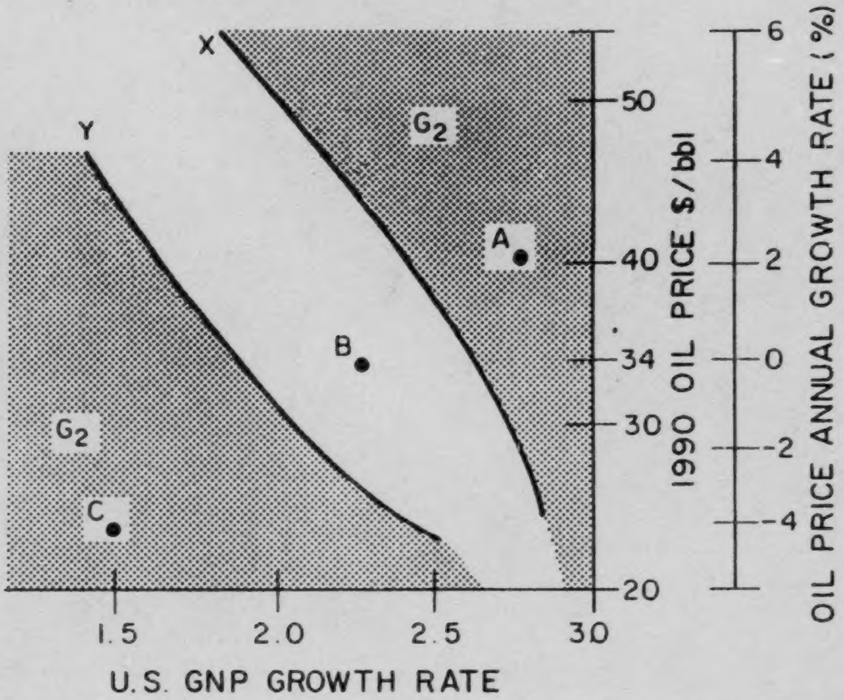

Figure 2. Oil price and GDP (1982 dollars): the influence of price on growth.

unlikely to be realized, even if oil prices drop below the 1982 level. If real oil prices are to increase at 4 to 6 percent per year over the decade, it is unlikely that world economies can sustain growth greater than about 50 or 60 percent of base levels. The boundary of this unlikely upper portion of G_2, denoted by line X, reflects the limits on how *well* the world is likely to be able to do between now and 1990.

Of course, there are some limits to how *bad* growth performance is likely to be, even given rising oil prices. Thus there is another portion of the set G_2, which represents downside prospects that also are judged "unlikely." This portion of G_2 may be described by the same process as before, only now comparing points like B and C in Figure 2. Point C falls in G_2, meaning that we judge it unlikely that realized growth over the decade will be as low as 50 percent of base levels, if oil prices decline by 4 percent per year on average over the period. Line Y depicts the limits on how badly the world is likely to do.

In Figure 3, G_1 and G_2 are superimposed to present the union (shaded) of the two sets of conditions.

$$G = G_1 \cup G_2 \tag{4}$$

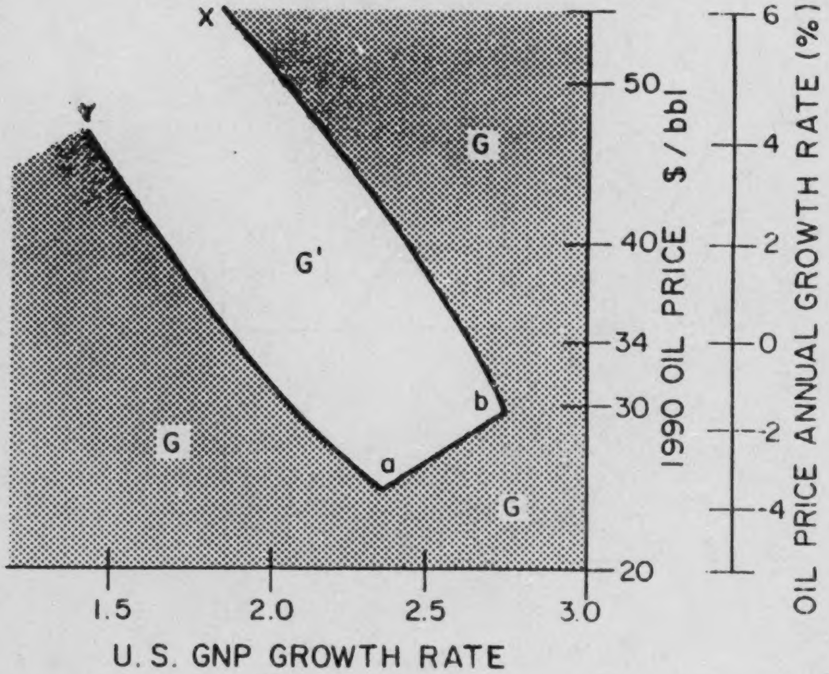

Figure 3. Oil price and GDP growth (1982 dollars): the combined effect of market clearing and growth conditions.

which the analysis shows are unlikely to come about over the next decade.

If one expects the members of the OPEC core always to produce at near capacity and Saudi Arabia to produce up to 8.5 million barrels per day whenever demand conditions call for it, then the likely combination (P, GDP[P]) is somewhere in the neighborhood of the line a–b in Figure 3.

Unfortunately, that is not the end of the story. Our supply model predicts the *capacity* of the core countries, not their actual production. And the line a–b in Figure 3 is for a Saudi maximum of 8.5 mbd—a number they can lower if they choose. In our set notation, we have defined a set G, which is unlikely; the complement G′—which contains the combinations ruled *not* unlikely—is unbounded to the upper left, as shown in Figure 3. The window has no top on it. To seek an upper bound, we must turn to an analysis of the behavior of the nations of the OPEC core.

Behavior of the OPEC Core

Hypotheses about OPEC behavior vary according to one's view of the relations among the members of the core, and the objectives these countries are likely to pursue over the decade. Here we demonstrate the results of one minimal pair of hypotheses. First, it is assumed that, as a group, the other members of the OPEC core will not cut back to less than 60 percent of capacity in order to support the price, and make room for the Saudis. Second, it is assumed that Saudi Arabia will try, to avoid going into deficit in the balance of trade in any year. That is, the Saudis will not hold great excess capacity (thereby holding up prices) if their foreign exchange revenues are not sufficient to cover their continuing growth of imports.

Of course, desired imports are not independent of oil revenues, so there is an element of simultaneity here. But for our calculations we assume the Saudis will want to sustain development plans as they existed in mid-1981, which implies import growth (in real terms) of roughly 7 percent per year over the 1980s.

The simulation model can be used to calculate that range of conditions (P, GDP) that, combined with this estimate of desired Saudi imports and the restriction on non-Saudi cutbacks, will yield a zero balance on Saudi current account in the most stringent year. The results are shown in Figure 4 as a heavy dotted line. To the upper left of the heavy dotted line,

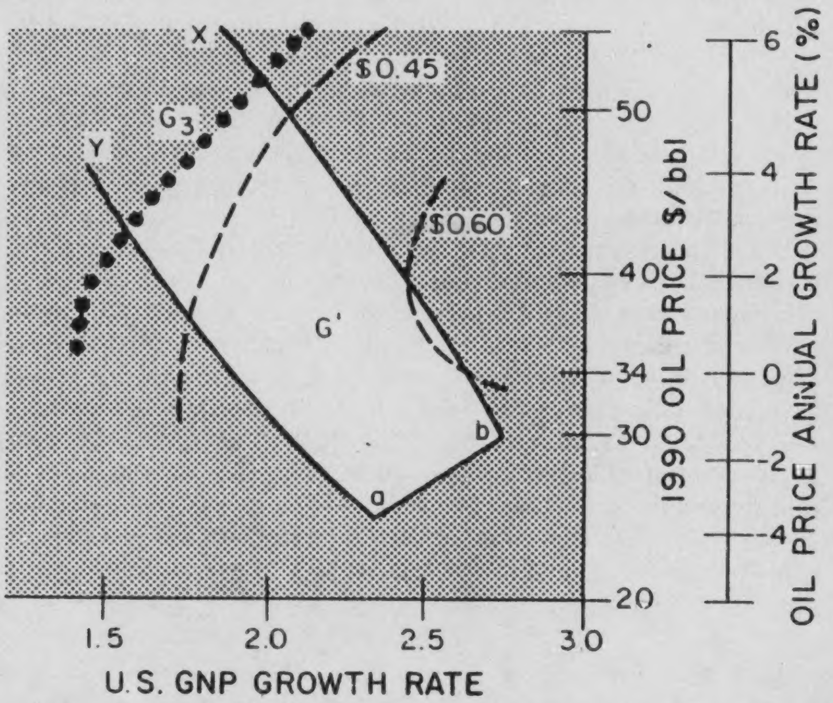

Figure 4. Oil price and GDP growth (1982 dollars): the window with smooth price adjustment.

Saudi foreign financial balances must decline in some year in order to finance an excess of imports over oil revenues. This calculation thereby defines a set G_3, which is unlikely (not impossible, but unlikely) to occur. The set G of unlikely events can then be defined as the union:

$$G = G_1 \cup G_2 \cup G_3, \qquad (5)$$

and the complement G′ defines a bounded envelope or window of likely oil price and world GDP growth combinations over the decade.

At this point, one of the most important conclusions of the analysis can be drawn: the window of prices that are "not unlikely" in 1990 is very large. By our analysis it stretches from as low as $25 to something in the neighborhood of $50 per barrel (in 1982 prices).[12] Prices outside this range seem unlikely; but *within* the likely set G′ there is only a much weaker set of arguments as to where the outcome ultimately will be. In our view, narrow-band forecasts of price to 1990 are to be treated with great suspicion.

Thus far in this analysis we have divided events into only two categories, unlikely and not unlikely. One can imagine a more complex definition of G′, which defines zones of relative likelihood, perhaps by use of probability distributions of demand elasticities and drilling effort, or similar distributions of economic growth rates under various conditions. Or one may argue that the top region of the window, where prices rise at 5 percent per year or more, is less likely because government actions will be called forth to change drastically (say, by rationing) our presumed relation of oil consumption to economic activity and the oil price.

We will not attempt these extensions here, largely because we feel there is so little basis for judgment regarding relative probabilities. In the case of Saudi behavior, however, there is one common hypothesis that is informative and easy to illustrate. The dashed lines in Figure 4 represent price-growth combinations that yield equal Saudi export revenues over the decade of the 1980s. The balances are discounted at a 5-percent real rate and stated in trillions of 1982 dollars. (Other discount rates would shift the iso-present-value lines, but yield little change in shape.) If one believes that the Saudi objective is maximization of financial wealth[13] (and that the Saudis are able to control oil prices), then these iso-present-value lines give a basis for judging some regions of G′ more likely than others. According to these results, the Saudis should set the oil price on a trajectory to around $36 in 1990, and hope the world will achieve GDP growth at around 85 percent of our assumed base rates.[14]

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[12] The figure shows results for a Saudi production limit of 8.5 mbd. If the Saudis produced at the 11.0-mbd limit (see Figure 1), the bottom of the window would imply an even further price decline to 1990.

[13] There is continuing debate about Saudi motives. See, for example, Moran (1978). For a discussion and survey of OPEC wealth-optimization models see Hammoudeh (1979).

The Influence of Events Beyond 1990

Because of the limitations of data and models, the analysis thus far has focused on the decade of the 1980s; there is no explicit influence of developments after 1990. Oil-rich countries presumably are also concerned about wealth in the longer term. How might these concerns influence the analysis, were we to incorporate them?

The shape and position of the window in 1990 seems largely independent of these long-term goals. The set G_1 has to do with oil supply and demand during the 1980s, as do the macroeconomic phenomena that lie behind G_2. The set G_3, which reflects assumed core and Saudi behavior, could in principle be changed by some long-run consideration, although we see no evident set of long-run concerns that would lead to a major revision.

The influence of longer-run concerns, then, should weigh most importantly not in the definition of the window itself, but on any attempt to classify some of the "not-unlikely" regions as being more likely than others.

IV. ONE MORE OIL SHOCK

One shortcoming of the analysis thus far is that actual oil price increases do not occur according to smooth exponential growth curves. The experience of 1973–74 and 1979–80 is of sharp shocks followed by periods of relative price stability in real terms as the higher price level is absorbed.[15] Many observers believe this type of shock will occur again, but there is serious question about how much more punishment the world economy can tolerate. Some argue that there will be only one more oil shock at most, and even its size is limited due to the likely effects of price on energy demand, both directly through the price effect and indirectly through the impact on economic growth.

Our analysis cannot fully answer this question, but it can shed some light on it by looking at the effect of a shock on the price window in 1990. To perform the experiment we assume the shock comes in 1984. Through 1983 the world oil price is assumed to hold constant (in real 1982 dollars) at $34 per barrel. World economic growth is assumed to proceed along the recession/recovery path described earlier. The price shock comes in 1984, and world GDP growth rates (again presumed constant) over the 1984–1990 period are different as a result. The calculation procedure described above for the smooth process is followed, and G_1 is calculated on the assumption that real oil prices hold constant through 1990 at their post-shock 1984 levels.

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[14] The shape of the iso-present-value lines is determined by the income and price elasticities implicit in our demand model, and by the production capacities of the core countries. These lines also are influenced by the assumptions about OPEC behavior. For example, if we assume the core acts as a wealth-maximizing unit, the lines are nearly vertical—leading to a desire to end up at point b in Figure 4.

[15] See Jacoby and Paddock (1980).

The results are shown in Figure 5. Again the vertical axis shows the price in 1990 (and which is in effect from 1984 to 1990), and the horizontal axis shows U.S. economic growth performance for 1984 to 1990, after the shock. As before, all country economic growth rates change proportionately. We have drawn in our impression of post-shock growth performance, noted as G_2 again, and the heavy dotted line representing the Saudi current account balance constraint is also shown, identifying G_3.

One may argue about the GDP[P] relationship, and Saudi behavior in the face of balance-of-payments deficits, but there is no doubt that the introduction of a shock makes a significant difference from the former analysis under smoothly changing prices. The upper limit of "not-unlikely" prices in

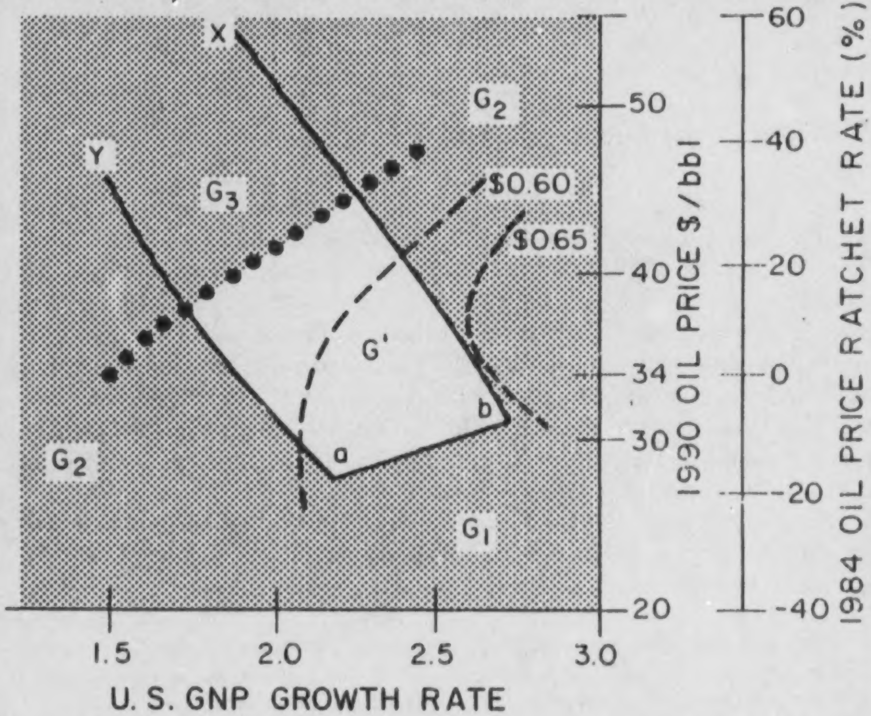

Figure 5. Oil price and GDP growth (1982 dollars): the window with an additional oil shock.

1990 is reduced from the case with smooth growth in price and GDP. The analysis shows that a 1984 ratchet of prices up to the $45 level would be sustained to 1990, but a greater increase probably would not. It also is not unlikely that the markets would clear to 1990 with no price increase above today's levels, or even fall into the range around $28.[16]

The implications for Saudi financial wealth also are shown in Figure 5 by the dashed lines. Again, if the Saudis are effective revenue maximizers, they would try to avoid any ratchet above the $34 to $35 level.

V. CONCLUSION

We have indicated a method by which analytical models, tempered with a large dose of judgment, can be used to describe a window of combinations of economic growth and oil prices through which the world likely will pass at the end of this decade. This window is large and illustrates the futility, and naiveté, of point forecasts. Many assumptions about demand and supply responses, and OPEC behavior, are necessary to fashion the crudest boundaries of this envelope, even with the best of supporting analytical tools. For a smoothly changing world the set of likely prices in 1990 ranges from $25 to $50 per barrel (in 1982 dollars); for a single shock in 1984 the range is $28 to $45 in 1990. Additional judgment can help carve out a more narrow region, but the foundations needed to support such analysis are weak.

These are results that, to our view, argue against the use of "reference cases" and "central" or "most likely" forecasts. Many analyses, and perhaps many decisions, would be improved if they more fully reflected the wide range of future oil prices about which little more can be said, based on our analysis, than that they are not unlikely.

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[16] As before in Figure 4, the results shown in Figure 5 are for a Saudi production limit of 8.5 mbd. If the Saudis would produce up to a 11.0 mbd limit (see Figure 1), no price jump could occur and be sustained.

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Mrs. LLOYD [presiding]. Thank you very much. I appreciate your testimony. I was trying to review it as best I could and I appreciate your input into our hearings.

On a general question, if any of you would like to respond or all of you is fine, I am wondering what evidence is there that the private sector is going to fund the developmental projects? How realistic do you think it is that the private sector is going to pick up where we are leaving the projects at the present time?

Mr. OATMAN. Was the question addressed to me?

Mrs. LLOYD. All of you can respond to it. I have my doubts that the private sector is going to pick up where we abandoned so many of our programs. I would like to know your reaction to that.

Dr. DREYFUS. To speak directly to the gas research situation, the fact is that the private sector has made an effort to pick up the reductions in the DOE budget but is unable to do so at least at the pace that would have been necessary.

The Department of Energy's gas-related research has been reduced by more than the total GRI program. The gas industry is a regulated industry and does most of its research through this arm so the answer is no. The budget situation is such and the ability in the industry is such that it may be many years before the kind of pace that was realized under a bigger Federal program is again regained.

Mrs. LLOYD. Thank you.

Mr. Oatman.

Mr. OATMAN. I would concur with that in terms of the Electric Power Research Institute. We feel the loss of a good deal of the basic research into coal and the availability of resources and it has caused us difficulty in trying to determine appropriate strategies for utilities. We are unable to pick up that research and to carry it forward because of our own budget limitations and the necessity of addressing immediate needs of the electric utility industry.

Mrs. LLOYD. Mr. Oatman, how much of EPRI's R&D budget is devoted to intermediate and long-term R&D versus the short-term R&D?

Mr. OATMAN. The near term research at EPRI now accounts for approximately 60 percent of our program funding. Intermediate research and development which we consider to be 10 to 25 years, accounts for 33 percent. Long-term research, which is 25 years or more, is, at this point in time, 5 percent of the total budget.

Mrs. LLOYD. So basically, the private sector does not have the funds to get into our long-term programs because of the payback for investment?

Mr. OATMAN. Well, one of the problems at EPRI is that the utility industry, over the past decade, has encountered a number of very immediate problems in terms of their financial situation. Consequently, there has been an increasing tendency toward nearer term payoff to meet the immediate problems of electric utilities.

Mrs. LLOYD. Mr. Dreyfus, how much of the GRI budget is devoted to intermediate and long-term R&D?

Dr. DREYFUS. It is a little bit difficult to characterize it directly, but certainly two-thirds or more of it would be characterized as near-term impact. We have placed a great deal of emphasis on efficient utilization which would have a near impact to retain industrial markets or reduce the residential cost burden. We have a supply side program which is concentrated to a great extent on unconventional gas resources which have the opportunity to make an early impact on the cost of production.

The longer term supplemental supply programs have become an increasingly smaller portion of our budget. We have, of course, had a growing budget so they are not necessarily decreasing in absolute terms. But they are a lesser proportion of the emphasis. So, by far, the predominant portion of our research is into that which will have an impact within ten years or less.

Mrs. LLOYD. Thank you very much.

I would like to ask this question and have all you gentlemen respond. Given our experiences over the past few years, what do you think is the most pressing need in the area of energy studies? Do you think we need to concentrate on improved and expanded data collection or additional models or what do you think is most pressing?

Dr. ADELMAN. May I speak briefly to that?

Mrs. LLOYD. Yes.

Dr. ADELMAN. The data base, as I pointed out in my prepared testimony, is actually shrinking. I am speaking now of economic data. We have lost some of the statistics that the American Petroleum Institute and the American Gas Association used to put out. The series that are supplied now to continue them by EIA are decidedly inferior. We are also losing the data base outside of this country and most countries.

On the latter score, I am afraid not a great deal can be done but something can because it is anomalous that where a good deal of money is being spent on modeling and calculation efforts, the grist that you put into the mill is getting less and is getting less reliable.

The other item, though, which is very much larger is that of basic research. The input of private industry is not growing any larger and there is a good reason why it probably won't. The payback, as you have said, Madam Chairman, is too long and the prospective profit for the individual company or even the individual trade group is too uncertain. That is where no private interests can serve the general welfare and that is where it is either Government or nobody.

Mrs. LLOYD. Thank you very much.

Mr. Darmstadter, would you like to comment?

Mr. DARMSTADTER. I think in two areas the intensive studies would be valuable. One relates to the very long-term distribution of the world energy resource base and our changes in the distribution of that resource and stock may affect the long-term interests and needs of the United States and of other countries both developing and developed. We realize that as demand shrinks, OPEC as the marginal supplier reduces its proportion of supplying current world energy or world oil requirements, at the expense of which the contribution of countries like Mexico and the United States increases.

As we look ahead to the year 2000 and to the early part of the 21st century, though, it is quite conceivable that the latter group of countries possessing what geologists tell us is a relatively small portion of that resource base that the contribution of those countries will shrink in the future and, in fact, that there will be more concentrated dependence on what are presently the group of OPEC countries than even today and some appreciation or recognition of that possibility and the policy consequences that derive therefrom, I think, could be quite illuminating and useful to us.

On quite another subject, I think, and this addresses really the heart of these hearings, we know just from the newspaper headlines surrounding the budget debate and from the kinds of information introduced by Dr. Rivlin that Government revenues are scarce. Government expenditure priorities are emotionally debated and deeply felt by various claimants on that limited resource base. So I think it is particularly important that in those energy R&D areas exacting large amounts of money that the most thoughtful decisionmaking process is deployed in our determination of which energy functions and areas deserve what amount of the limited funds available.

So that, for example, as we evaluate the experience of the Synthetic Fuels Corp. and contemplate its future, the next phase of its activities with the many billions of dollars that are implied already in commitments that are now being made and that may be in store for the future that we take a very hard and thoughtful and insightful look about what functions are most appropriately reserved for that enterprise which, for the market, and put that in the context of a well-rounded, well-balanced energy R&D effort across the board of the technologies, that we are interested in synfuels, nuclear, conservation, and still other things.

I think that in the next year or two that ought to be a front burner area of attention to public officials.

Mrs. LLOYD. The programs that can produce the most energy near at hand, the technologies that are nearest at hand should receive the greatest amount of funding?

Mr. DARMSTADTER. I think there is a balance between the near term and the long term and also at a point in time between those programs which turn out to be the most cost effective in terms of producing the most energy for the least investment in resources.

Dr. Rivlin addressed that question to some extent and you responded to it a bit in debating the issue of whether—and I don't have the expertise to address it in hard terms—but the question of whether, for example, there is some kind of misallocation in the relative priorities that are placed on the nuclear versus synfuels and versus fossil fuels, the application of truly rigorous tests of cost effectiveness to that whole spectrum and menu of choices that confront us.

Mrs. LLOYD. Thank you very much.

Dr. Dreyfus, would you like to respond?

Dr. DREYFUS. Yes. First of all, I would like to agree with Dr. Adelman that the most important thing that we have facing us right now is the maintenance of a decent statistical and information base. I think that there is quite a risk that in a period of laissez-faire government action in the energy industries we can get back to where we were in 1970 and 1973 when we had some very pressing policy decisions to make and essentially no knowledge upon which to make them.

Things are changing so rapidly in the energy business today that if we cease collecting adequate data for as long as 2 years, we will lose whatever comprehension we have about what is going on. If then some crisis comes up and new important public decisions have to be made, we will be about as ignorant as we were then.

I would like to disagree with Dr. Adelman on his view of synthetic fuels. My judgment is that we don't know, and he doesn't know, whether there is any place for synthetic fuels in the policy future in the United States. Therefore, I think it is important that the Federal Government, which is the only organization that is apt to do anything in synthetic fuels in these times, persist in trying to get some comprehension of what the real costs and benefits are of utilizing these very large domestic energy resources, such as oil shale for example, what the place of that really is. We don't know again. We didn't know in the last energy crisis and we could again get caught, as in project independence and other ideas based on no knowledge of what it really entails.

We need some synthetic fuels programs for information, for policy decision information purposes, and we won't get it from industry.

In a parochial sense, we would like to see more money in the gas technologies, more Federal involvement in the longer term or expensive kinds of research particularly in unconventional resources and keeping up with the basic science of gasification processes.

Mrs. LLOYD. Thank you.

Mr. Oatman.

Mr. OATMAN. I would just reinforce the need for information to reduce the uncertainty in the basic resources of coal, oil and natural gas; not only the price and availability, but the sensitivity of the price and availability to underlying factors such as depletion of the resource and the requirements for low sulfur coal. These are the kinds of information that are needed as the supply input to the decisions made by the electric utility industry.

One of the things that most concerns us on the demand side, in trying to determine the need for electricity at the end of very long lead times, is the relationship of the changing industrial structure to energy and electricity requirements. Many of the relationships represented in the present models perhaps are not going to pertain to the future. Industrial cost structures are changing and we are quite concerned and interested in how these changes will affect the need for electricity and that the availability of electricity will not constrain economic growth.

Mrs. LLOYD. Thank you.

Dr. Adelman, do you have any further comments?

Dr. ADELMAN. I would like to clarify the issue between Mr. Dreyfus and myself and put it this way: Synthesizing of oil or gas from coal means persuading a hydrogen molecule to latch on to a coal molecule. Under current processes, for every molecule you can get to do that, 100 go someplace else where you don't want them. They go into heat, undesired often toxic by-products or something. And the chemists and chemical engineers have been mulling over this for at least 50 years and more. I think that more of our efforts ought to be put into letting them find out what is really going on rather than in building great big plants.

Mrs. LLOYD. Thank you very much.

We will have additional questions that will be submitted to you in writing for the record. I am sorry, but we have run out of time because of our time constraints.

I want to thank you for being with us and for your contribution to these hearings. If there are no further comments, the committee stands adjourned.

[Whereupon, at 12:30 p.m., the subcommittees adjourned.]

APPENDIX I

ADDITIONAL QUESTIONS AND ANSWERS SUBMITTED FOR THE RECORD

DON FUQUA (Fla.), Chairman

ROBERT A. ROE, N.J.
GEORGE E. BROWN, JR., CALIF.
JAMES H. SCHEUER, N.Y.
RICHARD L. OTTINGER, N.Y.
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U.S. HOUSE OF REPRESENTATIVES
COMMITTEE ON SCIENCE AND TECHNOLOGY
SUITE 2321 RAYBURN HOUSE OFFICE BUILDING
WASHINGTON, D.C. 20515
(202) 225-6371

LARRY WINN, JR., KANS.
MANUEL LUJAN, JR., N. MEX.
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TOM LEWIS, FLA.

J. H. POORE
Executive Director
ROBERT C. KETCHAM
General Counsel
DAVID S. JEFFERY
Minority Staff Director

June 28, 1983

Mr. J. Erich Evered
Administrator
Energy Information Administration
U.S. Department of Energy
Washington, D.C. 20585

Dear Mr. Evered:

We want to thank you for your excellent testimony before the Subcommittee on Energy Development and Applications and the Subcommittee on Energy Research and Production on June 22 on the subject of lower oil prices and their implications for energy research and development policy. We would like to supplement the record of the hearing with some additional questions on this topic. Also included are a number of questions submitted by minority Members of the Subcommittees.

We appreciate your cooperation on this matter. If you have any questions regarding this request, please contact Dr. Harlan Watson of the staff of the Subcommittee on Energy Development and Applications at (202) 225-4320.

Sincerely,

Marilyn Lloyd

DON FUQUA, Chairman
Subcommittee on Energy
Development and Applications

MARILYN LLOYD, Chairman
Subcommittee on Energy
Research and Production

DF/ML:Wba
Enclosure

Lower Oil Prices: Implications for Energy R&D Policy
Additional Questions for Mr. Evered

1. Has your decision to concentrate EIA's efforts on short- to medium-term projections been driven primarily by funding considerations or more to your lack of confidence in the efficacy of long-term forecasts?

2. What role has EIA played in the development of the preliminary 1983 National Energy Policy plan (NEPP-83) energy projections? Will EIA have any input prior to the issuance of the final NEPP-83 energy projections?

Supplemental Minority Questions for Mr. Evered

1. There has been some criticism that several of the assumptions used in the EIA model for natural gas are 12 to 18 months out of date. What are some of the asssumptions that EIA has used in developing its natural gas model? Do these models reflect the most recent market conditions? For example, does the EIA model reflect the recent development of the gas spot market, with its attendant consequences for natural gas prices? If not, why not?

2. To what extent do these models take into account recent proposals discussed in the various natural gas legislative initiatives now under consideration in Congress? For example, how does the EIA modeling work take into account the prospects for contract renegotiations in the near-term and over the last six months? Do these assumptions accurately reflect current business practices? If so, please justify.

3. How sensitive are the results of various gas models to changes in assumptions? In particular, how do these assumptions affect various natural gas supply and production estimates? How do you account for the wide range in gas prices predicted as a result of the Administration's proposal under the EIA model and the Policy Office Projections?

4. Why does EIA in its recent study project more natural gas demand in 1985 (3.2 Tcf) and 1990 (2.0 Tcf) than EIA did in its 1983 gas study? What factor does fuel-switching play in making these projections? How do these projections for fuel-switching relate to today's conditions and what might be expected in the future in light of today's conditions?

5. How sensitive are natural gas projections to various world oil price projections? For example, several recent projections have suggested that world oil prices may begin to rise again in 1985. What impacts on natural gas prices might result if these projections turn out to be wrong, which has also been suggested by several other recent oil company forecasts?

Department of Energy
Washington, D.C. 20585

July 26, 1983

Honorable Don Fuqua
Chairman, Subcommittee on Energy
Development and Applications
Committee on Science and Technology
House of Representatives
Washington, D.C. 20515

Dear Mr. Chairman:

Enclosed are answers to the questions you submitted in your letter dated June 28, 1983, to Administrator J. Erich Evered following his appearance on June 22, 1983, before the Science and Technology Joint Subcommittees on Energy Research and Production and Energy Development and Applications concerning lower oil prices and their implications for energy research and development policy.

If you have any questions, please call Hank Edler or Tom Pretorius of my staff on 252-4277. They will be happy to assist you.

Sincerely,

Thomas H. Pretorius
for Robert G. Rabben
Assistant General Counsel
for Legislation

Enclosure

cc: Ms. Christine Wegman
Subcommittee Staff

Q. Has your decision to concentrate EIA's efforts on short to medium-term projections been driven primarily by funding considerations or more to your lack of confidence in the efficacy of long-term forecasts?

A. As I stated in my testimony, long range projections have limited value. One must recognize that it is unlikely that long-term projections will be very accurate. Many events which cannot be anticipated in the projections will affect future consumption, production, and prices.

The appropriation for the Energy Information Administration (EIA) for fiscal year 1983 was not sufficient to conduct all programs that are required by statute. Accordingly, priorities had to be placed on the programs competing for these limited resources. My decision was to devote these resources consistently with Congress' action on the 1983 budget. The action reflected my judgment, which was communicated to the Congress in its consideration of the 1983 Budget, that among the array of statutory functions performed by EIA, the National Energy Information System should be maintained at an acceptable level of quality because it is most vital to our mission of carrying out a central, comprehensive, and unified energy data and information program. The legislative history to the EIA appropriation suggests that Congress expected that this core function be funded rather than other statutory requirements such as the Financial Reporting System, mid- and long-term forecasting activities, and the Coal Reserves Disclosure Report.

Q. There has been some criticism that several of the assumptions used in the EIA model for natural gas are 12 to 18 months out of date. What are some of the assumptions that EIA has used in developing its natural gas model? Do these models reflect the most recent market conditions? For example, does the EIA model reflect the recent development of gas spot market, with its attendant consequences for natural gas prices? If not, why not?

A. EIA's assumptions and data are as current as possible and reflect market conditions. They are contained in Chapters 3 and 4 and the Appendices of the Natural Gas Market Through 1990, An Analysis of the Natural Gas Policy Act and Several Alternatives, Part IV. The recent developments of a spot or brokered market are not large and, by design, of a very narrow focus. For example, most have been designed to alleviate current take-or-pay problems. These types of brokered transactions appeared, then disappeared, during the interstate shortages in the late 1970's. Currently, the natural gas market is very volatile and is constantly changing but this may be only a temporary response to the overall problems. At the same time, we agree that the events that have taken place over the past year are a response to a current market problem and should be carefully observed for any significant implication they may have over the long term.

Q. What role has EIA played in the development of the preliminary 1983 National Energy Policy Plan (NEPP-83) energy projections? Will EIA have any input prior to the issuance of the final NEPP-83 energy projections?

A. Preparation of NEPP-83 has been managed by DOE's Office of Policy, Planning and Analysis. That office uses a variety of sources in preparing the projections contained in the NEPP-83, including the projections prepared by EIA. EIA was consulted on the historical data contained in the preliminary projections and has been given the opportunity to comment on the projections during their development. EIA has made extensive comments on the final draft of the projections.

Q. To what extent do these models take into account recent proposals discussed in the various natural gas legislative initiatives now under consideration in Congress? For example, how does the EIA modeling work take into account the prospects for contract renegotiations in the near-term and over the last six months? Do these assumptions accurately reflect current business practices? If so, please justify.

A. EIA has analyzed the NGPA and proposals by the Administration, Representatives Addabbo, Gephardt, Slattery, and Representative Sharp's Committee Print. We have also analyzed continued control and phased decontrol. EIA assumes contracts operate as written and renegotiations can and will take place, but assumed that renegotiations take place within the terms of the contracts. EIA's contracts data base classifies contracts according to their terms. The analysis is based on the contracts data base, and is therefore driven by the conditions in individual contracts. The analysis assumes that those contracts with renegotiation and market-out provisions will be exercised, but that companies will not violate the limits of their contracts. No unilateral contract action is assumed to take place.

Q. How sensitive are the results of various gas models to changes in assumptions? In particular, how do these assumptions affect various natural gas supply and production estimates? How can you account for the wide range in gas prices predicted as a result of the Administration's proposal under the EIA model and the Policy Office Projections?

A. Changes in economic assumptions cause greater changes in results in the various natural gas models than changes in policy assumptions. For example, the assumptions that we make with respect to the world oil price, finding rates, pipeline tariffs, behavior of producers, pipelines and distribution companies, and demand produce results that vary more than the results produced by policy changes. The wide range in gas prices predicted by the models is due to differences in these basic assumptions.

Q. Why does EIA in its recent study project more gas demand in 1985 (3.2 Tcf) and 1990 (2.0 Tcf) than EIA did in its 1983 gas study? What factor does fuel-switching play in making these projections? How do these projections for fuel-switching relate to today's conditions and what might be expected in the future in light of today's conditions?

A. In May 1983, the EIA published its 1982 Annual Energy Outlook (AEO) which contained forecasts of energy futures. The Natural Gas Market through 1990, An Analysis of the Natural Gas Policy Act and Several Alternatives, Part IV (Part IV Report), which also contains forecasts, differs from the AEO in three major respects:

- It is based upon more current data, updated assumptions, and it reflects the nature of existing natural gas contracts, pricing provisions, take-or-pay provisions, and deregulation provisions.

- It is based upon a detailed analytical model that was designed to provide the capability of assessing the flow of gas annually from producing regions through pipelines to distributors, in line with historic market patterns. This model was developed to permit an analysis of questions regarding regional impacts, prices in the interstate and intrastate markets, production, and the market impact(s) of long-term contracts.

- Market segmentation (the level of disaggregation), market clearing (national versus pipeline system), transmission, distribution, dispatching decisions of electric utilities, and fuel-switching differ in the two models. Detailed information may be obtained in the two reports above.

The same basic assumptions concerning world oil price and economic growth are used in the AEO and the Part IV Report. However, differences in approach to the analysis of behavior of national gas markets provide alternate views of what might happen to natural gas production, consumption, and price.

Production and consumption differ by 3.3 Quads in 1985 and 2.2 Quads in 1990 between projections in the Part IV Report and the AEO primarily in electric utilities due to the analytic approach and regional detail. These differences are associated with corresponding differences in the prices of refined petroleum products and and gas at the burner tip.

Within the Part IV Report, the NGPA and proposed alternatives are all compared using a consistent framework of assumptions and expected market behavior.

EIA is currently working to improve its analyses of fuel switching. It is very difficult to sort out the reasons for decreases in natural gas consumption. They could be due to general economic conditions, fuel switching, or weather.

Q. How sensitive are natural gas projections to various world oil price projections? For example, several recent projections have suggested that world oil prices may begin to rise again in 1985. What impacts on natural gas prices might result if these projections turn out to be wrong, which has also been suggested by several other recent oil company forecasts?

A. EIA projects that world oil prices may start up in 1985. Increses in the GNP (and subsequent changes in the demand for energy) and fuel choice decisions (for example, between oil and gas in the U.S. market are the most important factors affecting world oil prices. The impact of world oil prices on the natural gas market is significant and would change projections considerably. For example, lower world oil prices lower the price of residual fuel oil which competes with gas, but at the same time stimulate the economy and the demand for all energy, including gas. Higher than assumed oil prices raise the residual fuel oil price but decrease overall energy demand.

DON FUQUA (Fla.), Chairman

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COMMITTEE ON SCIENCE AND TECHNOLOGY
SUITE 2321 RAYBURN HOUSE OFFICE BUILDING
WASHINGTON, D.C. 20515
(202) 225-6371

LARRY WINN, JR., KANS.
MANUEL LUJAN, JR., N. MEX.
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TOM LEWIS, FLA.

J. H. POORE
Executive Director
ROBERT C. KETCHAM
General Counsel
DAVID S. JEFFERY
Minority Staff Director

June 28, 1983

Mr. Jan W. Mares
Acting Director
Policy, Planning and Analysis
U.S. Department of Energy
Washington, D.C. 20036

Dear ~~Mr. Mares~~ Jan:

We want to thank you for your excellent testimony before the Subcommittee on Energy Development and Applications and the Subcommittee on Energy Research and Production on June 22 on the subject of lower oil prices and their implications for energy research and development policy. We would like to supplement the record of the hearing with some additional questions on this topic. Also included are a number of questions submitted by minority Members of the Subcommittees.

We appreciate your cooperation on this matter. If you have any questions regarding this request, please contact Dr. Harlan Watson of the staff of the Subcommittee on Energy Development and Applications at (202) 225-4320.

Sincerely,

Don
DON FUQUA, Chairman
Subcommittee on Energy
Development and Applications

Marilyn
MARILYN LLOYD, Chairman
Subcommittee on Energy
Research and Production

DF/ML:Wba
Enclosure

ADDITIONAL QUESTIONS FOR JAN MARES
Hearing on Lower Oil Prices: Implications for Energy R&D Policy
June 22, 1983

1. You mention on page 8 of your testimony that a lessening of urgency for oil substitution will reduce pressure for crash demonstration projects. Should this lessening of urgency reduce pressure for deliberative, non-crash demonstration projects, and, if so, will the government be forced into the more risky crash demonstrations if and when the situation again becomes urgent?

2. DOE's report on "THE FUTURE OF ELECTRIC POWER IN AMERICA" (FEPA) at page ES 11 states that the broad public perception that constructing new coal and nuclear facilities substantially increases the price of electricity is incorrect. Upon what do you base this conclusion?

3a. What is the Department's conclusion regarding the relationship between the growth in energy and the growth in the country's Gross National Product? Please provide the Subcommittees with a chart of the growth in energy utilization plotted against the growth in GNP for the past 30 years.

3b. Does the relationship between energy and GNP also hold for electricity growth and GNP? If so, why? If not, why not? Please provide the Subcommittees with a chart of the growth in electric energy utilization plotted against the growth in GNP for the past 30 years.

4. If the country plans for economic recovery, such that the Gross National Product would increase at a rate of 3% or more per year, should the policy of this country be to encourage growth of electricity production at or above the growth in the planned Gross National Product?

5. DOE mentions on page 19 of the FEPA report that non-cash earnings for utilities through the allowance for funds used for construction accounting mechanism have contributed to the financial decline of electric utility industry. One mechanism for remedying the paper earnings problem of the utilities is to allow them to collect some amount of the funds spent for construction work in progress through the rate base. What is the Department's position on allowing construction work in progress to be incorporated into the rate base?

6. DOE mentions on page 22 of the FEPA report that the "grace period" of excess capacity is coming to an end. What are the implications for the utilities concerning commitments to new construction in the near future?

7. Prior to the Arab Oil Embargo in 1973, electricity growth had grown constantly at around 7 1/2% per year. On page 26 of the

FEPA report it is stated that substantial conservation of electricity has deferred the day of reckoning for electric power. Has conservation reduced the rate of growth of electricity from 7 1/2% per year, about two times the rate of growth in Gross National Product, to around 3% per year, equal to the Gross National Product rate of growth?

8. Would you comment, in the context of the FEPA report, on Harvard economist Peter Navaro's contention that, with oil at $30 a barrel, it becomes cheaper to build and operate new coal or nuclear power plants than to operate existing oil-fired plants?

9. Electricity prices have increased 4% annually in real terms since 1970. Oil, gas, and coal prices have increased 9 - 16%. Does this disparity in growth of prices for the various fossil fuels increase the tendency of industry and others to switch to electricity as an alternative to these fuels?

10. How does the utilities' financial condition compare with the financial condition of industrial companies? To what extent does DOE believe that the price of electricity will influence how electricty demand growth rises with respect to GNP growth?

11. Does the Department believe that nuclear power will supply an increasing share of U.S. energy requirements through the year 2000?

12. Some forecasters have predicted a move to smaller decentralized electric generating units and away from large central generating stations. Does the Department agree with these projections?

13. Does the Department forecast a shortage of electricity capacity and thus an increased incidence of forced brownouts in the latter part of this decade or the next?

14. Does the Department believe that incentives for the construction of electrical capacity are necessary?

15. Why did DOE request a 73 percent increase for the FY 1984 enhanced oil recovery program over the FY 1983 level if the petroleum industry has underway some 220 enhanced oil projects and is investing about $200 million a year?

ADDITIONAL MINORITY QUESTIONS FOR JAN MARES
Hearing on Lower Oil Prices: Implications for Energy R&D Policy
June 22, 1983

1. How sensitive are the results of various gas models to changes in assumptions? In particular, how do these assumptions affect various natural gas supply and production estimates? How can you account for the wide range in gas prices predicted as a result of the Administration's proposal under the EIA model and the Policy Office Projections?

2. How sensitive are the natural gas projections to various world oil price projections? For example, several recent projections have suggested that world oil prices may begin to rise again in 1985. What impacts on natural gas prices might result if these projectons turn out to be wrong, which has also been suggested by several other recent oil company forecasts?

Department of Energy
Washington, D.C. 20585

July 28, 1983

Honorable Don Fuqua
Chairman, Subcommittee on Energy
Development and Applications
Committee on Science and Technology
House of Representatives
Washington, D.C. 20515

Dear Mr. Chairman:

Enclosed are answers to the questions you submitted in your letter dated June 28, 1983, to Acting Director, of Policy, Planning and Analysis, Jan W. Mares, following his appearance on June 22, 1983, before the Science and Technology Joint Subcommittees on Energy Research and Production and Energy Development and Applications concerning lower oil prices and their implications for energy research and development policy.

If you have any questions, please call Hank Edler or Tom Pretorius of my staff on 252-4277. They will be happy to assist you.

Sincerely,

Thomas H. Pretorius
for Robert G. Rabben
Assistant General Counsel
for Legislation

Enclosure

cc: Ms. Christine Wegman
Subcommittee Staff

Additional Questions
Hearing on Lower Oil Prices
House Science & Technology
June 22, 1983

Question 1: You mention on page 8 of your testimony that a lessening of urgency for oil substitution will reduce pressure for crash demonstration projects. Should this lessening of urgency reduce pressure for deliberative, non-crash demonstration projects, and, if so, will the government be forced into the more risky crash demonstrations if and when the situation again becomes urgent?

Answer: The lessening of urgency for oil substitution has provided the nation with an opportunity to develop a sound base of technical experience in synthetic fuels and other energy systems, both within our R&D laboratories and at commercial scales. We continue to support the activities of the U.S. Synthetic Fuels Corporation (SFC) in providing financial incentives to a diversity of commercial-scale synthetic fuel projects. Included in the projects backed to date by the SFC are the nation's first commercial-scale oil shale project (the Union project) and the first commercial demonstration of the integrated coal gasification/combined cycle electrical generating concept (the Cool Water project). The Department of Energy is also continuing to provide loan guarantee assistance to the first commercial high-Btu gas-from-coal project, the Great Plains coal gasification plant, construction of which is now more than 60 percent complete.

We believe actions such as these, where the private sector has the lead role in choosing the technology, then designing and constructing first-of-a-kind commercial-scale facilities, with the federal government serving principally to provide financial risk-sharing assistance, is a preferable and more productive approach than the former DOE demonstration program where the government was the principal project sponsor. This coupled with a sound research and development program concentrating on the more fundamental, generic aspects of the technology, should minimize, if not eliminate, the need for the government to be forced into more risky crash demonstrations if and when the energy situation again becomes urgent. Perhaps more importantly, the clear distinction in the roles of government and industry in developing and deploying new energy technologies removes the government as a competitor to private sector commercial ventures and creates a more competitive market environment. This should ensure that the most efficient, cost-effective, and publicly-acceptable energy technologies are the ones that eventually enter the marketplace.

Question 2: DOE's report on "THE FUTURE OF ELECTRIC POWER IN AMERICA" (FEPA) at page ES 11 states that the broad public perception that constructing new coal and nuclear facilities substantially increases the price of electricity is incorrect. Upon what do you base this conclusion?

Answer: The real price of electricity nationwide is not expected to increase much if at all in real terms in much of the Nation in the next two decades (see p. 5-36 of FEPA), except in the southwest (Texas, Oklahoma, Louisiana), where rising natural gas prices are likely to cause substantial real price increases over the rest of the 1980s. (On the Pacific Coast as a whole, prices are projected to increase slightly in real terms; in the Pacific Northwest, the latest BPA projection shows that between 1983 and 2000, rates will rise 1.0% annually in real terms.)

This projection of electricity prices is consistent with historic experience. In the 1970s and early 1980s rising fuel prices, not new plants, was the most important factor in driving up electricity rates. Figure 5-5 of FEPA (p. 5-12) shows that the utilities which did not burn much oil or gas had the smallest real increases in price between 1972 and 1981, although many new plants were added in that time frame. Figure 5-3 (p. 5-9) illustrates this same point for specific utilities. The four most expensive utilities, whose prices rose significantly in real terms, are oil fired utilities (as noted in the text, San Diego and Long Island Lighting rose over 100% in real terms). However, the less expensive utilities, whose prices rose very little if at all in real terms, burned little or no oil. Table 5-2 (p. 5-15) shows that several utilities which added large amounts of capacity, even though they had little expensive oil and gas to displace, had smaller nominal rate increases than several utilities that added little capacity.

Figure 5-7 shows that if a midwestern utility had added a large amount of excess capacity in the 1970s, driving its reserve margin to 60%, it would have raised its rates only 11% by building this unneeded capacity. This example shows that new plants will raise rates if the plants are not needed at the time they are built, but continued use of oil or gas will cause rates to be much higher than construction of unneeded capacity.

New plants will generally lower rates over time, relative to what they would have been, if expensive oil and gas fuels are displaced (see pp. 5-22 thru 5-31, and Figures 5-6, 5-9, 5-10, and 5-11).

With all this evidence that new plants raise rates little in real terms over time, and that they lower rates relative to what they would have been if they displace expensive oil and gas fuels, why do many people believe that new plants raise rates substantially?

Public perception about the cost of new plants appears to be largely based upon two phenomena: news reports of billion dollar price tags and cost overruns at a limited number of expensive nuclear plants, and the "rate shock" associated with putting some new plants into service.

Some of the more expensive new nuclear plants, especially if there is little or no expensive oil or gas to displace on the utility system, will raise rates in real terms over time. What the public does not see, however, is that virtually all new coal plants and most new nuclear plants are being built at costs far less than those of the highest cost plants like the WPPSS plants or Shoreham. For instance, the 6 units Commonwealth Edison will bring on line between late 1982 and late 1986 (one of these units is currently on line) will cost about $1100/kw in 1983$, compared to Shoreham's cost of about $3600/kw (also 1983$). That is about 30% of the cost of Shoreham. Many other new nuclear plants are coming on line in the near future at costs closer to the Commonwealth Edison plants than to Shoreham.

Attachment A shows the cost/kw of all new coal plants that came on line in 1982 plus costs on a limited number of future coal plants. Note that only one of the 12 investor owned utility coal plants cost as much as $1000/kw.

The "rate shock" phenomenon occurs because of electric utility accounting procedures. There is probably no other good for which consumers pay a first year cost, in nominal dollars, that is twice as high as the tenth year cost. Figures 5-9 through 5-11 (pp. 5-24 through 5-26) illustrate how the actual cost of power from a new plant declines over time. Home mortgages, for instance, are generally repaid in flat monthly payments. If utilities recovered capital investment in plants from their customers the way home mortgages are paid, there would be smaller and fewer instances of "rate shock," and less perception on the part of ratepayers that new plants substantially raise the price of electricity. As it is, a new plant that will lower rates over time on a net present value basis may give ratepayers the wrong impression because of this temporary "rate shock".

Based on the evidence, as we see it, there are some instances where new plants will add to the cost of electricity. But new plants in general need not do so and overall we would expect them to help hold down electric rates. We recognize of course that there are alternative views on this issue.

COST/KW OF ALL COAL PLANTS COMING ON LINE IN 1982 (SELECTED POST-1982 PLANTS ALSO INCLUDED) (Invester-Owned Utilities) [4/]

Pre-1983

Plant Name (Utility)	Size	Cost/KW	First Year of Operation
Scherer 1 (Georgia Power)	818 MW	$924[3/]	1982
Weston 3 (Wisconsin P.S)	300 MW	$720	1982
Mill Creek 4[1/] (Louisville Gas and Electric)	470 MW	$454	1982
Newton 2 (Central Illinois P.S.)	600 MW	$530	1982
Crystal River 4, 5 (Florida Power Corp.)	640 MW each	$695 (average)	1982, 1984
Killen 2 (Cincinnati Gas and Electric)	661 MW	$822/KW	1982
Welsh 3 (Southwestern Electric Power)	528 MW	$355/KW	1982
Tolk 1 (Southwestern Public Service)	508 MW	$500	1982
Rodemacher 2 (Central Louisiana Electric)	530 MW	$539	1982
Nelson 6 (Gulf States Utilities)	540 MW	$981	1982
Gibson 5[1/] (Public Service Indiana)	625 MW	$678	1982
San Juan 4 [1/], [5/], [6/], [7/], [8/]	472 MW	$1175	1982

Post 1983

Pirkey 1[1], [2]	(Southwestern Electric Power)	640 MW	$832/KW	1985
Dolet Hills 1[1], [2]		640 MW	$875/KW	1986
Tolk 2		508 MW	$560	1985
(Southwestern Public Service)				
A.B. Brown 2[1] (Southern Indiana Gas and Electric)		250 MW	$990	1986

---

[1] Includes scrubber

[2] Lignite plant (higher capital costs than coal plants)

[3] Scherer 1's costs include all the common facililty costs for 3 additional units; unit 2, due in service in 1984, will cost $590/kw.

[4] Cost include AFUDC and expenses for connecting with the grid (transmission lines, etc.)

[5] Includes NO_x control

[6] Includes extra scrubber module to meet state SO_2 standards more stringent than Federal standards.

[7] Includes waste water recovery technology and costs beyond those required for other plants, resulting in zero water discharge.

[8] Environmental controls represent 42% of capital costs of unit.

COST/KW OF ALL COAL PLANTS COMING ON LINE IN 1982
(Non Investor-Owned Utilities)

Plant Name (Utility)	Size	Cost/KW	First Year of Operation
Shiras 3[1] (Marguette Dept of Light & Power)	43.7 MW	$1142	1982
Merom 2[1] and 3[1] (Hoosier Energy)	490 MW each	$ 776 (combined)	1982 and 1983
McIntosh 3[1] (City of Lakeland)	329	$ 692	1982
Thomas Hill 3[1] (Associated Elec. Coops)	630	$ 810	1982
Unnamed by Request (Unnamed by Request)	400	$ 962	1982
Laramie River 1[1], 2[1], 3[1] (Basin Elec. Coop)	550 each	$ 970 (combined)	1980, 1981, 1982

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[1] Includes scrubber

[2] Costs include financing costs and expenses for connecting with the grid (transmission lines, etc.)

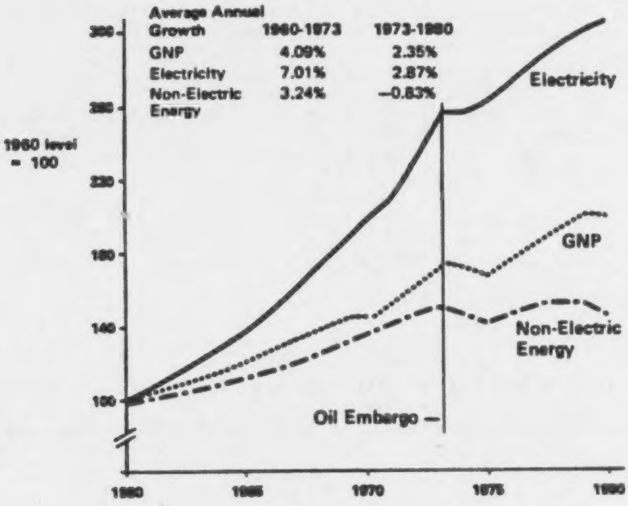
Question 3a: What is the Department's conclusion regarding the relationship between the growth in energy and the growth in the country's Gross National Product? Please provide the Subcommittees with a chart of the growth in energy utilization plotted against the growth in GNP for the past 30 years.

Question 3b: Does the relationship between energy and GNP also hold for electricity growth and GNP? If so, why? If not, why not? Please provide the Subcommittees with a chart of the growth in electric energy utilization plotted against the growth in GNP for the past 30 years.

Answer: The historical relationships between GNP growth, growth in electricity use, and growth in energy use generally are shown in Figure 3-1 and Table 3-1 (attached). The energy intensity of GNP declined significantly over the period from 1960-1980, particularly after the embargo in 1973. However, this decline in the energy-intensity of GNP was confined to non-electric energy forms; during this same period, the electricity intensity of GNP rose, even after the embargo. Major, long-term changes in the prices of competing energy forms have been the principal factors behind these shifts, although other factors have been involved as well. (See Question 7 concerning some of the other factors.) According to our projections (Figure 3-37, attached) the energy intensity of GNP will continue to decline through the year 2000, while the electricity intensity of GNP will remain relatively constant at about 2.7 quads of delivered electricity per trillion dollars of GNP (in 1980$). Significant changes in key parameters would of course change these projections.

Figure 3-1

Growth of GNP and Delivered Energy



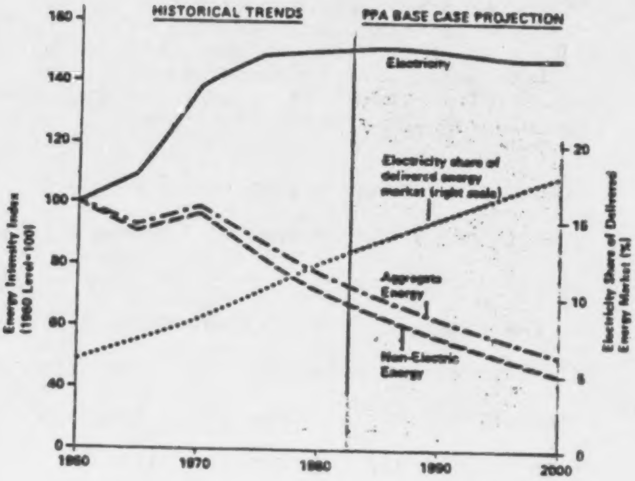
SOURCE: State Energy Data Report, U.S. Department of Energy, July 1982.
State Btu Unit Price Database, U.S. Department of Energy.
Economic Report of the President, 1982.

Table 3-1

Energy Intensity of GNP and Market Shares for Electricity and Non-Electric Energy (for 1960, 1973 and 1980)

	1960	1973	1980
Energy Intensity (Delivered quads demanded per trillion dollars of GNP, in 1980 dollars)			
Electricity	1.80	2.63	2.73
Non-electric energy	27.18	24.52	19.63
Aggregate energy	29.18	27.15	22.36
Market Share (Percent of total delivered energy)			
Electricity	6.17	9.69	12.21
Non-electric energy	93.83	90.31	87.79
Total	100.00	100.00	100.00

SOURCE: State Energy Data Report, U.S. Department of Energy July 1982.
State Btu. Unit Price Database, U.S. Department of Energy.
Economic Report of the President, 1982.


HISTORICAL TRENDS
PPA BASE CASE PROJECTION
Electricity
Electricity share of delivered energy market (right scale)
Aggregate Energy
Non-Electric Energy
Energy Intensity Index (1960 Level=100)
Electricity Share of Delivered Energy Market (%)
0
40
60
80
100
120
140
160
0
5
10
15
20
1960
1970
1980
1990
2000

Question 4.	If the country plans for economic recovery, such that the Gross National Product would increase at a rate of 3% or more per year, should the policy of this country be to encourage growth of electricity production at or above the growth in the planned Gross National Product?
Answer:	Electricity demand growth will be (and should be) determined by the choices of consumers in the energy market place. Electricity supply planning is fundamentally the responsibility of the electric utilities, under the supervision of their respective state or local regulatory authorities. This is entirely appropriate, given the considerable variance to be expected in regional and local economic growth rates, costs of alternative generation technologies, availability of low-cost opportunities for conservation of electricity, etc. Federal policy in this context should be to facilitate healthy non inflationary economic growth and to support rational regulatory practices which will enable utilities to make new capital investments as appropriate.

Question 5: DOE mentions on page 19 of the FEPA report that non-cash earnings for utilities through the allowance for funds used for construction accounting mechanism have contributed to the financial decline of electric utility industry. One mechanism for remedying the paper earnings problem of the utilities is to allow them to collect some amount of the funds spent for construction work in progress through the rate base. What is the Department's position on allowing construction work in progress to be incorporated into the rate base?

Answer: It is the Administration's policy to advocate regulatory reform that encourages the construction of economically efficient electric generating facilities. As part of this effort, the Department of Energy (DOE) believes that a more widespread use of CWIP by regulatory bodies would help to counter the current "capital averse" behavior on the part of privately-owned electric generating companies. Thus the Department's position is to advocate inclusion of CWIP in rate bases, recognizing however that CWIP is not a panacea for the industry's problems.

Inclusion of CWIP in rate bases would assist the industry's liquidity problem which has arisen largely due to increased construction costs and lead times. In 1967, for example, when a generating unit could be installed in as little as 30 months, CWIP comprised only 13 percent of total industry assets. During this period, cash represented 92 percent of total earnings. By the end of 1981, when lead times had extended to as long as 14 years, CWIP had grown to 25 percent of total assets. Cash meanwhile, had decreased to 46 percent of earnings.

The Department testified in support of CWIP before the Federal Energy Regulatory Commission (FERC) on December 7, 1981. FERC is currently implementing a recent rulemaking which will permit CWIP on a limited basis in utility ratebases under their jurisdiction. We support FERC's effort as a prudent step toward constructure regulatory reform.

Question 6: DOE mentions on page 22 of the FEPA report that the "grace period" of excess capacity is coming to an end. What are the implications for utilities concerning commitments to new construction in the near future?

Answer: If growth rates for electricity demand average about 3% or more in the next two decades, large numbers of new plants will probably be needed by the early 1990s and beyond in many parts of the U.S. (see Figure 4-2 of the FEPA). The implication is that utility commitments to new units will have to be made within the next few years in order to avoid either the possibility of less reliable supply of electricity, or reliance upon uneconomic expedients such as reversion of obsolescent plants to baseload usage, or other means of meeting demand, such as increased usage of purchased power, construction of combustion turbines, or increased reliance upon Canadian hydro.

Question 7. Prior to the Arab Oil Embargo in 1973, electricity growth had grown constantly at around 7 1/2% per year. On page 26 of the FEPA report it is stated that substantial conservation of electricity has deferred the day of reckoning for electric power. Has conservation reduced the rate of growth of electricity from 7 1/2% per year, about two times the rate of growth in Gross National Product, to around 3% per year, equal to the Gross National Product rate of growth?

Answer: If "conservation" is understood to mean increased efficiency of electricity use in response to rising electricity prices, the answer is basically yes. That is, prices have risen substantially, users have found ways to use electricity more efficiently, and the rate of electric demand growth, relative to GNP growth, has declined. However, the lower rate of electric demand growth should not be attributed only to price changes. There have been other contributing factors, such as slower population growth, increasing saturation of certain key appliance markets (freezers, air conditioners), and changes in the composition of industrial output.

Question 8: Would you comment, in the context of the FEPA report, on Harvard economist Peter Navarro's contention that, with oil at $30 a barrel, it becomes cheaper to build and operate new coal or nuclear power plants than to operate existing oil-fired plants?

Answer: The costs, over time, of building and operating a new coal or nuclear plant will generally be less than the costs of continuing to use oil electricity at $30/bbl (1982$), especially if real price escalation in oil prices is expected to occur in the 1990s and beyond.

Work done for DOE by ICF, Incorporated shows that the "breakeven" oil price, assuming no escalation of oil price in real terms, is about $32/bbl if the capital cost of the coal plant is high (about $1600/kw in 1982 $). The "breakeven" oil price, again assuming no oil price escalation in real terms, is about $26.50/bbl if the capital cost of the coal plant is on the low end of the expected range (about $1000/kw in 1982 $).

There is substantial variation in the costs of new plants, especially for nuclear plants. Of the new coal plants coming on line in 1982, however, only two had a cost over $1000/kw: one was a small 44 MW plant, and the other had NO_x and SO_2 controls excess to federal standards as well as zero water discharge, thereby causing environmental controls to comprise 42% of the plant's capital cost. For the investor-owned utilities, 5 of the 12 plants were built for less than $600/kw. Thus costs for new plants in the range of $1000 to $1600/kw (in 1982 $) are quite reasonable, and are consistent with estimates of the Energy Information Administration.

Question 9. Electricity prices have increased 4% annually in real terms since 1970. Oil, gas, and coal prices have increased 9 - 16%. Does this disparity in growth of prices for the various fossil fuels increase the tendency of industry and others to switch to electricity as an alternative to these fuels?

Answer: Yes -- assuming, as we do, that over the next two decades electricity will continue to become more competitive in price with other energy forms. Our projections show electricity's share of total delivered energy rising from about 13% today to about 18% by 2000, and we think this is probably a conservative estimate, given our assumptions.

Question 10: How does the utilities' financial condition compare with the financial condition of industrial companies? To what extent does DOE believe that the price of electricity will influence how electricity demand growth rises with respect to GNP growth?

Answer: As to the first part of your question, there are a number of ways to compare the financial condition of electric utilities with other industries. One way is to measure investor reactions via stock market prices on the leading stock exchanges. A common approach to measurement and one we will use here is to use indexes such as the Standard and Poors 500 (the 500 leading stocks) and the Argus Electric Index (the 50 largest electric stocks).

Using this indexing approach we find that electric stocks outperformed the S&P 500 in both 1981 and 1982. In 1981 the average share of common stock from the Argus 50 appreciated about 5% in nominal terms and in 1982 about 23%. Correspondingly, the average S&P share lost about 8% of its price in 1981 and appreciated 18% in 1982. Thus, over the two year period electric stocks on average appreciated 28% while the S&P appreciated about 5%. Beginning in mid-August of last year however, this price trend begin to take a dramatically different path. From August to December of last year the S&P index rose 33% while electric stocks rose about 16%.

A continuation of changed investor perceptions has carried over to 1983. From January to June of this year, the S&P has appreciated about 14% while electric stocks only about 5%. Any appreciation in stock prices is good news for the industry compared to several years ago when prices were falling, but for a variety of reasons, investors appear more bullish about non-utility stocks than about utilities, at least for the present.

This pattern of electric stocks periodically outperforming the market only to be overhauled by the market is not confined to recent history. Indeed, this pattern has occurred in each of the last four recession-recovery cycles (dating back to mid-1960s). Consequently, looking at comparative statistics for one or even two years can mislead the observer into believing the utilities' troubles are over. A longer period of observation confirms the fact that regulation impedes utilities from realizing fully the gains achieved by the unregulated portion of the economy during recovery periods. More importantly, this long-term trend implies that the incentives to invest are much lower for regulated electric utilities than for unregulated companies.

It is important to recognize that the financial health of the electric industry is the responsibility of both utility management and the industry's regulators. At the same time the Department emphasizes the importance of regulatory policies that will encourage construction of economically efficient plants and that permit economic growth at a reasonable cost to consumers. More specifically, while avoiding capital investment may have been a sound financial tactic in response to negative investment incentives in the past, the best interests of the Nation as a whole will be well served should this practice continue.

A simple answer to the second part of your question is to note that if the price of any commodity rises (or falls) faster than that of other goods and services, demand for that commodity will fall (or rise) accordingly. However, the extent to which demand will shift in response to a given price is not obvious. Two price effects need to be measured to determine consumer responses to price changes.

The first is to measure consumers' willingness or ability to modify their use of a commodity in response to its own change in price. The second effect is that of consumers' willingness or ability to substitute one commodity for another in response to a change in their relative prices. In the course of the Electricity Policy Project we evaluated these factors (historically and prospectively) and found that price rises in virtually all forms of energy will, between now and the year 2000, tend to reduce the demand for energy in the aggregate. But because we expect electricity prices to rise much more modestly than other energy forms, we think the share of electricity usage in the delivered energy market will continue to grow. The net effect of these two countervailing trends, in our projections, is electricity demand growth at a rate approximately the same as GNP growth.

Question 11: Does the Department believe that nuclear power will supply an increasing share of U.S. energy requirements through the 2000?

Answer: Because the amount of nuclear plants still under construction is large, nuclear energy will be a larger percentage of total electrical generation in 2000 than it was in 1980. The table below, from the preliminary NEPP-1983 projections, details the Scenario B nuclear capacity and percentage of electricity produced by nuclear for the years 1980, 1982, 1990, and 2000:

YEAR	NUCLEAR CAPACITY (GW)	PERCENTAGE OF ELECTRICITY PRODUCED BY NUCLEAR	NUCLEAR ENERGY AS PERCENT OF ALL ENERGY CONSUMED
1980	55	11.1%	3.4%
1982	60	12.5%	4.1%
1990	114	20.4%	7.5%
2000	130	20.2%	8.5%

There are uncertainties about the number of nuclear plants that will go into service in the future. Virtually all of the plants that have little money invested in them have already been cancelled, though. The number of additional plant cancellations is likely to be small, as assumed in the figures above. Beyond 1990, the uncertainty will concern whether new nuclear plants not currently on the drawing boards are built.

Question 12: Some forecasters have predicted a move to smaller decentralized electric generating units and away from large central generating stations. Does the Department agree with these projections?

Answer: Some forecasters have predicted a move to smaller conventional units, others have predicted a move to smaller "alternative technology" units. We'll discuss these two issues separately.

CONVENTIONAL PLANTS

Smaller conventional plants can usually be built somewhat faster than larger units (construction on a 300 MW coal plant might be completed about 6 months sooner than on an 800 MW unit), and for smaller plants a smaller percentage of utility earnings will consist of non-cash AFUDC in the years just prior to commercial operation of the plant. Thus, utilities might gain a slight financial advantage by building smaller plants.

Another advantage to small plants is that for smaller utilities capacity can be more easily matched with load growth with small plants. Of course, several utility companies sharing the construction of larger units will have the same effect as building smaller units without partners.

A disadvantage to building smaller plants is that they cost more per kw than larger units, so that total capital costs would be higher over time if a given capacity target were met with smaller rather than larger units.

Finally, an unanswered question is whether larger units will have lower availability/capacity factors than smaller units. Evidence at the present time is that the first generation of larger units had relatively low availability factors for reasons not necessarily related to size -- e.g. the first forced draft and supercritical systems -- but that the more recent generation of large units are performing at good availability factors.

On balance, there may be more small conventional units built in the future. This will probably present a small financial benefit to the utility, but may possibly present a slight economic disbenefit to consumers, if in fact the availability factors of larger units are reasonably comparable to those of smaller units.

ALTERNATIVE TECHNOLOGIES

Most alternative technologies are much smaller than even small conventional coal plants. Wind machines are about 2 MW or less; low head hydro units are usually less than 15 MW; cogeneration units are usually less than 50 MW, although they can be larger; geothermal plants today range in size up to about 120 MW; photovoltaics can be rooftop applications.

These technologies can be built by utilities or by other entities. If they are built by other entities, then the utility faces no financial exposure, and thereby benefits. If they are built by the utility, they can be financially advantageous for several possible reasons: expenses might be passed through directly, construction time will be shorter, and project size will be smaller.

Whether such plants are economically advantageous to customers is technology and application-specific. Pacific Gas and Electric has been building economic geothermal units at the Geysers since the early 1960s. Many utilities have built cost-effective hydro systems, large and small, for decades. More low head hydro systems, and many cogeneration systems -- especially those that are relatively large and use relatively inexpensive fuels such as coal and wood -- have the potential to be economic. However, section 210 of PURPA, has the potential to cause the displacement of more economic generation types with less economic generation types because it establishes preferential rates for which only some technologies are eligible.

The recent interim report by the Congressional Research Service on cost-effective alternatives to conventional capacity projected that the total amount of capacity displaced in 2000 by cogeneration, wind, and small hydro was under 12 GW. No estimate of capacity displacement by passive or direct solar technologies was made. In conclusion, we currently expect there will be some movement to smaller plants in the next decade. The extent of development in alternative technologies is unlikely to be large, but the penetration rate may be determined as much by financial pressures as by economics, which makes prediction more difficult. There may also be some movement to smaller conventional plants, but financial reasons may also play as much or more of a role as economic reasons in such a shift.

Question 13: Does the Department forecast a shortage of electricity capacity and thus an increased incidence of forced brownouts in the latter part of this decade or the next?

Answer: No. As indicated in the answer to Question 6, the electric utility industry has a number of means by which it can continue to meet load if demand growth outstrips its ability to build coal-fired and nuclear baseload units. It is likely that utilities would adopt a variety of such measures to avoid brownouts, blackouts, scheduled load-shedding, etc. The general effect of these measures, however, would probably be higher prices than if the baseload units had been built.

Question 14: Does the Department believe that incentives for the construction of electrical capacity are necessary?

Answer: If regulators permit companies to earn a market rate of return on their investments, the companies will then have the incentives which are needed. However, disincentives to investment currently exist which discourage electric utilities from investing in economically efficient capacity. Considering that this industry has failed to earn its allowed rate of return for ten years, that its cash earnings are only about 60 percent of the dividends it pays out, that its market-to-book ratio is only 40 percent of the level it attained in the 1960s, that its bond ratings have experienced serious erosion over recent years, and that more than half of its current earnings result from an accounting artifact called Allowance For Funds During Construction (AFUDC), it is apparent that the industry in general is faced with substantial disincentives for new capital investment. These disincentives work against new capital investments whether they be new generation, transmission or distribution facilities, conservation programs, load control or time of day metering. An industry laboring under such constraints will not have the financial strength to make the investments necessary to assure reliable future supplies at minimum cost.

For the sake of completeness, it should be noted that not all indicators are bleak. Inflation has come down significantly in the past two years, for example, reducing the problems from what they could have been had double-digit inflation continued. In addition, the growth of demand has slowed, giving some utilities more time to determine how much capacity is needed how soon. Nevertheless, the financial problems noted above pose a threat to the industry which sensible regulation, primarily at the state level, can help to alleviate.

The Department does not believe that any federal financial incentives for the construction of electrical capacity are needed. The Department believes that electricity supply is primarily a matter for utilities and states to determine. Those states that regulate sensibly can expect to have reliable and economical supplies. Those that do not can expect to face the consequences -- higher costs, unreliable supplies, or perhaps a combination of both.

DON FUQUA (Fla.), Chairman

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JAMES H. SCHEUER, N.Y.
RICHARD L. OTTINGER, N.Y.
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U.S. HOUSE OF REPRESENTATIVES
COMMITTEE ON SCIENCE AND TECHNOLOGY
SUITE 2321 RAYBURN HOUSE OFFICE BUILDING
WASHINGTON, D.C. 20515
(202) 225-6371

LARRY WINN, JR., KANS.
MANUEL LUJAN, JR., N. MEX.
ROBERT S. WALKER, PA.
WILLIAM CARNEY, N.Y.
F. JAMES SENSENBRENNER, WIS.
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General Counsel
DAVID S. JEFFERY
Minority Staff Director

June 28, 1983

Dr. Alice Rivlin
Director
Congressional Budget Office
United States Congress
Washington, D.C. 20515

Dear Dr. Rivlin:

We want to thank you for your excellent testimony before the Subcommittee on Energy Development and Applications and the Subcommittee on Energy Research and Production on June 22 on the subject of lower oil prices and their implications for energy research and development policy. We would like to supplement the record of the hearing with some additional questions on this topic.

We appreciate your cooperation on this matter. If you have any questions regarding this request, please contact Dr. Harlan Watson of the staff of the Subcommittee on Energy Development and Applications at (202) 225-4320.

Sincerely,

DON FUQUA, Chairman
Subcommittee on Energy
Development and Applications

Marilyn Lloyd
MARILYN LLOYD, Chairman
Subcommittee on Energy
Research and Production

DF/ML:Wba
Enclosure

Lower Oil Prices: Implications for Energy R&D Policy
Additional Questions for Dr. Rivlin

1. In your testimony, you mention that an oil import fee could be as effective at reducing oil imports as an energy R&D program. Isn't an oil import fee an expensive device for accomplishing that goal?

2. What level of federal expenditures does CBO expect to occur in the synfuels program and what will determine this level?

3. What if your oil price forecasts are wrong and prices resume the high growth rates once projected for them? Shouldn't we continue a synfuels development program as "insurance" against this possibility?

4. Could you briefly describe the basis on which you disaggregate federal R&D funding into basic research, applied research, and development?

5. You mentioned that the government has a poor track record when it comes to selecting technologies for commercial development. Could you give us some examples? What are the reasons this record is so poor?

6. You mentioned that it might be more appropriate to focus on antitrust issues than direct federal funding to encourage private sector research. Do you believe that the approach stipulated in H.R. 3393 (attached) will address the problems in antitrust that you perceive?

HIGH TECHNOLOGY R&D JOINT VENTURE ACT OF 1983

Summary

This legislation addresses a significant institutional barrier affecting high technology research and development joint ventures. It would provide immunity (and exemption) from Federal and similar State antitrust laws for any venture if it meets certain statutory requirements. These requirements relate to the length of the venture (fifteen years), patent rights, and administrative and managerial requirements (the establishment of a management board), among others. The venture must also meet an initial capital formation test in order to ensure that the R&D market remains competitive and can accommodate at least four ventures of any one type.

The Attorney General must be notified of the formation of a venture in order to qualify under this legislation. In addition, the Attorney General is authorized to investigate any venture to ensure that the venture has complied with the requirements of this Act.

Finally, this legislation specifies that any joint research and development venture will be subject only to actual damages if it fails to meet the requirements of this Act and is held in violation of the Federal antitrust laws. It also requires any court to award attorney's fees to any defendant who successfully defends a claim that he was in violation of the antitrust laws.

FLOOR STATEMENT OF THE
HON. F. JAMES SENSENBRENNER, JR. (R-WIS.)

THE HIGH TECHNOLOGY RESEARCH AND DEVELOPMENT JOINT VENTURE ACT OF 1983

JUNE 22, 1983

MR. SPEAKER, TODAY I AM INTRODUCING LEGISLATION JOINTLY WITH THE DISTINGUISHED GENTLEWOMAN FROM TENNESSEE (MRS. LLOYD) TO HELP OUR NATION MOVE FORWARD IN DEVELOPING IMPORTANT NEW HIGH TECHNOLOGIES IN SUCH AREAS AS SEMICONDUCTOR CHIPS, MICROPROCESSORS AND SUPERCOMPUTERS, SENSORS, CHEMICAL AND MATERIAL SCIENCES, ROBOTICS, AND ALTERNATIVE ENERGY SYSTEMS, AMONG MANY OTHERS. THIS LEGISLATION, THE HIGH TECHNOLOGY RESEARCH AND DEVELOPMENT JOINT VENTURE ACT OF 1983, WOULD HELP OUR NATION MAINTAIN ITS WORLD ECONOMIC LEADERSHIP AND STIMULATE NEEDED RESEARCH AND DEVELOPMENT ACTIVITIES. IT WOULD ALSO HAVE SIGNIFICANT SECONDARY BENEFITS INCLUDING THE CREATION OF NEW JOBS, THE GROWTH OF VARIOUS SUPPORT INDUSTRIES AND THE GENERATION OF ADDITIONAL TAX REVENUES THROUGH INCREASED ECONOMIC ACTIVITY.

AS MANY OF MY COLLEAGUES ARE AWARE, OUR RECENT

ECONOMIC ILLS HAVE BEEN CAUSED BY SEVERAL FACTORS. ONE KEY FACTOR, POINTED OUT IN VARIOUS ECONOMIC INDICATORS, HAS BEEN OUR COUNTRY'S NOTABLE DECLINE IN INDUSTRIAL PRODUCTIVITY. WHILE THERE HAVE BEEN IMPRESSIVE INNOVATIONS IN MANY OF OUR BASIC INDUSTRIES, THE OVERALL RATE OF GROWTH IN AMERICA'S INDUSTRIAL PRODUCTIVITY SLOWED CONSIDERABLY DURING THE 1970S. IN FACT, OUR DOMESTIC PRODUCTIVITY ACTUALLY DECLINED A COUPLE OF POINTS IN 1981. THIS DANGEROUS TREND IS ONE WHICH OUR NATION CANNOT AFFORD TO TOLERATE AND WHICH MUST BE REVERSED AS SOON AS POSSIBLE.

BY MANY ACCOUNTS OUR DECLINE IN PRODUCTIVITY IS REPRESENTATIVE OF AMERICA'S ERODING TECHNOLOGICAL LEADERSHIP AND LAGGING INTERNATIONAL COMPETITIVENESS. THIS SITUATION CAN BE TRACED TO MORE THAN A DECADE OF LOW CAPITAL INVESTMENT AND LIMITED R&D SPENDING. ALTHOUGH THE U.S. STILL LEADS THE WORLD IN SPENDING FOR BASIC RESEARCH, A 1980 HARVARD BUSINESS REVIEW REPORT POINTED OUT THAT THE PRIVATE SECTOR INVESTMENT IN RESEARCH AND DEVELOPMENT HAS BEEN STEADILY DECREASING IN RECENT YEARS WITH NO CHANGES FORESEEN IN THE FUTURE.

A RECENT STUDY BY THE PRESTIGIOUS BUSINESS - HIGHER EDUCATION FORUM HAS STRESSED THE STRONG NEED TO ENHANCE OUR PRIVATE INDUSTRY'S ABILITY TO COMPETE WITH FOREIGN VENTURES IN DEVELOPING AND MARKETING NEW TECHNOLOGIES.

WITHOUT A FIRM COMMITMENT TO BASIC RESEARCH AND DEVELOPMENT, OUR LEADERSHIP IN MANY NEW TECHNOLOGICAL AREAS MAY BE SEVERELY CHALLENGED IN THE FUTURE. FOR EXAMPLE, THE JAPANESE ARE CLOSING FAST ON THE AMERICAN LEAD IN SUCH AREAS AS MICROCHIP TECHNOLOGY, THREATENING U.S. PREEMINENCE IN THIS IMPORTANT TECHNOLOGY. THESE TINY ELECTRONIC DEVICES WILL BE AT THE HEART OF OUR FUTURE ADVANCES IN COMPUTERS, COMMUNICATIONS, CONSUMER PRODUCTS AND MANY OTHER AREAS.

THE FUTURE CHALLENGE TO AMERICA IN TECHNOLOGY DEVELOPMENT IS AWESOME. INTERNATIONAL COMPETITIVENESS HAS MADE IT MORE DIFFICULT THAN EVER TO DEVELOP AND EXPLOIT NEW INVENTIONS. IT IS CERTAINLY IN OUR NATION'S ECONOMIC AND NATIONAL SECURITY INTERESTS TO ENCOURAGE NEW IDEAS AND DEVELOP NEW TECHNOLOGIES, ALLOWING US TO MOVE FORWARD AND HELP LAY THE FOUNDATION FOR OUR FUTURE MODERN SOCIETY.

THE URGENCY OF OUR PRESENT SITUATION HAS BEEN MADE CLEAR IN A RECENT REPORT BY A PRESTIGIOUS NATIONAL RESEARCH COUNCIL PANEL. IN ITS REPORT ENTITLED INTERNATIONAL COMPETITION IN ADVANCED TECHNOLOGY: DECISIONS FOR AMERICA; THIS PANEL CONCLUDED THAT,

> THE UNITED STATES MUST ACT NOW TO PRESERVE ITS BASIC CAPACITY TO DEVELOP AND USE ECONOMICALLY ADVANCED TECHNOLOGY. THIS INNOVATIVE CAPACITY IS ESSENTIAL FOR THE SELF-RENEWAL AND WELL-BEING OF THE ECONOMY

> AND THE NATION'S MILITARY SECURITY. TRADE IN ADVANCED TECHNOLOGY PRODUCTS AND SERVICES WILL CONTRIBUTE ENORMOUSLY TO OUR ECONOMIC HEALTH. ADVANCED TECHNOLOGY PRODUCTS AND PROCESSES NOT ONLY PERMEATE THE ECONOMY, INCREASING PRODUCTIVITY, BUT ALSO FORM THE BASIS OF MODERN DEFENSE HARDWARE.

THIS REPORT ALSO WENT ON TO RECOMMEND THAT CAREFUL ATTENTION BE GIVEN TO "MAINTAINING THE HEALTH AND EFFECTIVENESS OF BOTH UNIVERSITY- AND INDUSTRY-BASED RESEARCH, EDUCATION AND TRAINING."

THE LEGISLATION WE ARE INTRODUCING TODAY REPRESENTS A SIGNIFICANT STEP IN MEETING THIS NATIONAL CHALLENGE. IT RECOGNIZES THAT THE MOST EFFECTIVE FEDERAL ACTIONS TO STIMULATE LONG-TERM PRIVATE INVESTMENTS IN RESEARCH AND DEVELOPMENT ARE THOSE THAT REMOVE POTENTIAL STRUCTURAL BARRIERS TO SUCH INVESTMENT. THIS LEGISLATION ATTEMPTS TO OVERCOME THESE INSTITUTIONAL BARRIERS AND ALLOW A WIDE RANGE OF BUSINESSES AND FIRMS TO CARRY OUR PRODUCTIVE RESEARCH ON A JOINT BASIS.

SEVERAL RECENT REPORTS, INCLUDING THE PREVIOUSLY - MENTIONED NATIONAL RESEARCH COUNCIL AND BUSINESS-HIGHER EDUCATION FORUM STUDIES, HAVE CALLED FOR A RELAXATION IN ANTITRUST RESTRICTIONS THAT PRESENTLY HINDER AMERICAN INDUSTRY'S ABILITY TO TAKE ADVANTAGE OF NEW HIGH TECHNOLOGIES. THE NATIONAL RESEARCH COUNCIL REPORT STRONGLY SUPPORTED A CAREFUL REEXAMINATION OF OUR ANTITRUST POLICIES, STATING THAT,

> WHILE U.S. ANTITRUST POLICY HAS BEGUN TAKING

> INTERNATIONAL COMPETITION INTO ACCOUNT, ITS IMPLEMENTATION STILL FAILS TO GIVE SUFFICIENT WEIGHT TO INTERNATIONAL TRADE CONSIDERATIONS. THE MANNER IN WHICH ANTITRUST STATUTES ARE INTERPRETED AND APPLIED IS CHARGED WITH INTERFERING IN INTERNATIONAL COMPETITIVENESS. FOR EXAMPLE, FIRMS HAVE DIFFICULTY RETAINING THE BENEFITS OF RESEARCH THAT ARE THE PRODUCT OF MULTIFIRM COLLABORATION, PROSPECTIVE "SAFE - HARBOR" RULINGS ARE NOT READILY AVAILABLE, AND THERE IS A GENERAL UNCERTAINTY REGARDING WHAT CORPORATE ACTIONS MAY ELICIT LEGAL ACTIONS ON THE BASIS OF ANTI-TRUST LEGISLATION.
>
> BECAUSE OF THIS UNCERTAINTY, MANAGEMENT CITES ANTI-TRUST POLICY AS CREATING EXCESSIVE RISK FOR A RANGE OF ACTIVITIES THAT MAY BENEFIT INNOVATION AND TRADE, SUCH AS POOLING RESEARCH EFFORTS, POOLING INFORMATION ON THE WORK OF INTERNATIONAL COMPETITORS, OR POOLING DEVELOPMENT PROGRAMS WHOSE COSTS ARE TOO LARGE FOR ANY ONE FIRM IN AN INDUSTRY TO UNDERTAKE. BY CONTRAST, FOREIGN GOVERNMENTS -- FOR EXAMPLE, JAPAN AND FRANCE -- ENCOURAGE COOPERATION AMONG FIRMS THROUGH MERGERS OR COOPERATIVE PROGRAMS.

IN ESSENCE, THE LEGISLATION WE ARE INTRODUCING TODAY WOULD PROVIDE NEW STATUTORY GUIDELINES FOR JOINT RESEARCH AND DEVELOPMENT VENTURES IN ORDER TO DETERMINE WHETHER THESE VENTURES WERE IN COMPLIANCE WITH FEDERAL AND SIMILAR STATE ANTITRUST LAWS. THESE GUIDELINES WOULD ALSO EXTEND TO ANY PARTICIPANT IN THE VENTURE, AS WELL AS ALL TO EMPLOYEES IN THE VENTURE.

IN ORDER TO QUALIFY UNDER THESE NEW LEGISLATIVE GUIDELINES, THE VENTURE PARTICIPANTS WOULD HAVE TO NOTIFY THE ATTORNEY GENERAL OF THE UNITED STATES THAT THEY PLAN TO ENTER INTO A JOINT RESEARCH AND DEVELOPMENT VENTURE. THIS VENTURE

WOULD ALSO HAVE TO IDENTIFY AND DEFINE ALL OF THE SPECIFIC RESEARCH AND DEVELOPMENT PROGRAMS THAT IT PLANNED TO UNDERTAKE. THE LENGTH OF ANY VENTURE COULD NOT EXCEED 15 YEARS. ANY JOINT VENTURE PARTICIPANT WOULD BE EXEMPT FROM ANY RESTRICTIONS ON OUTSIDE, INDEPENDENT RESEARCH AND DEVELOPMENT ACTIVITIES OR ANY OBLIGATIONS TO PROVIDE THE VENTURE WITH THE RESULTS OF ANY INDEPENDENT WORK. THE ULTIMATE AUTHORITY FOR THE MANAGEMENT OF THE JOINT VENTURE WOULD BE VESTED IN A MANAGEMENT BOARD, TO BE COMPOSED OF ONE REPRESENTATIVE FROM EACH PARTICIPANT IN THE VENTURE.

THE LEGISLATION SPECIFICALLY CONTEMPLATES THAT NEW FIRMS COULD JOIN THE VENTURE AT A FUTURE DATE IF THIS WAS AGREED TO BY THE VENTURE PARTICIPANTS, BUT THEY WOULD BE REQUIRED TO PAY A PROPORTIONAL SHARE OF THE COMMON EXPENSES OF THE VENTURE. THIS LEGISLATION CONTEMPLATES, AS A GENERAL RULE, FOUR OR MORE VENTURES IN ANY PARTICULAR AREA. IF THE AGGREGATE SHARES OF THE PARTIES TO THE CONTRACT IN THE RELEVANT MARKET, AS OF THE TIME THE THE CONTRACT IS MADE, FOR RESEARCH AND DEVELOPMENT PROJECTS IN CONNECTION WITH A PARTICULAR LINE OF COMMERCE EXCEEDED AT ANY TIME 25 PERCENT OF THE RELEVANT MARKET FOR ALL RESEARCH AND DEVELOPMENT PROJECTS IN THE SAME LINE OF COMMERCE, THE CONTRACT WOULD NOT BE COVERED UNDER THIS LEGISLATION UNLESS THE ATTORNEY GENERAL FOUND EITHER (1) THAT THE RESULTS OF THE PROGRAM WERE NOT LIKELY TO BE DIRECTLY APPLICABLE TO THE FUTURE PRODUCTION OF A MARKETABLE PRODUCT, (2) THE PARTICIPATION OF ALL THE PARTIES WAS NECESSARY

TO THE SUCCESS OF THE PROGRAM AND WAS LIKELY TO PRODUCE EFFECTS THAT INCREASED COMPETITION, IMPROVED THE NATIONAL ECONOMY OR FURTHERED NATIONAL SECURITY, OR (3) SUCH CONTRACT WAS MADE FOR THE PURPOSE OF CARRYING OUT RESEARCH AND DEVELOPMENT ESSENTIAL TO DEVELOP A PRODUCT THAT WAS NECESSARY TO ACHIEVE COMPLIANCE WITH ANY FEDERAL LAW RELATING TO THE QUALITY OF THE ENVIRONMENT. THE PARTIES MAY REQUIRE THAT THE ATTORNEY GENERAL DETERMINE WHETHER THEIR CONTRACT MET THIS MARKET TEST. THE ATTORNEY GENERAL'S DETERMINATION IN THIS MATTER WOULD BE CONCLUSIVE.

UNDER THIS LEGISLATION, ALL OF THE PARTIES IN THE JOINT VENTURE WOULD RETAIN TITLE TO ALL INVENTIONS, PATENTS OR OTHER USEFUL INFORMATION DEVELOPED IN THE COURSE OF THE VENTURE. ALL PARTICIPANT FIRMS WOULD ALSO BE ENTITLED TO OBTAIN IRREVOCABLE, NONEXCLUSIVE AND EQUIVALENT LICENSES TO ALL PATENTS OBTAINED BY THE PARTIES. AFTER THREE YEARS, LICENSES WOULD THEN BE MADE AVAILABLE TO ANY OTHER U.S. FIRM ON REASONABLE TERMS.

THIS LEGISLATION WOULD ALSO ALLOW THE ATTORNEY GENERAL TO INVESTIGATE ANY JOINT VENTURE AT ANY TIME IN ORDER TO INSURE THAT THE REQIREMENTS OF THE ACT ARE BEING MET. WHENEVER THE ATTORNEY GENERAL COMMENCED AN INVESTIGATION, HE WOULD BE REQUIRED TO NOTIFY THE VENTURE. IF THE ATTORNEY GENERAL DETERMINED THAT THE VENTURE VIOLATED THIS ACT, HE WOULD BE REQUIRED TO SUBMIT A WRITTEN NOTICE TO THE PARTIES

IN THE VENTURE, STATING THE FACTS AND REASONS SUPPORTING HIS DETERMINATION AND SPECIFYING THE ACTIONS THAT WOULD BE REQUIRED TO BRING THE VENTURE IN CONFORMANCE WITH THE REQUIREMENTS OF THIS ACT.

FINALLY, THIS LEGISLATION PROVIDES THAT NO PARTY SHALL BE LIABLE IN EXCESS OF ACTUAL DAMAGES FOR ANY JOINT RESEARCH AND DEVELOPMENT VENTURE THAT FAILS TO MEET THE REQUIREMENTS OF THIS ACT AND THE FEDERAL ANTITRUST LAWS. UNDER THESE CIRCUMSTANCES, THESE PARTIES WOULD ALSO BE HELD LIABLE FOR THE COST OF SUIT AND INTEREST AWARDED FROM THE DATE OF JUDGMENT.

MR. SPEAKER, RESEARCH AND DEVELOPMENT HAS BEEN ONE OF THE PRIMARY BASES ON WHICH OUR NATION HAS ATTAINED ITS WORLD ECONOMIC STANDING. THE LEGISLATION WE ARE INTRODUCING TODAY WILL HELP OUR NATION MAINTAIN THIS LEADERSHIP BY ENCOURAGING PRIVATE INVESTMENT IN HIGH TECHNOLOGIES. IT CONTAINS MANY ESSENTIAL ELEMENTS THAT ARE NECESSARY IF WE ARE EVER TO TAP THE RISK POTENTIAL OF PRIVATE RESEARCH AND DEVELOPMENT. I ENCOURAGE MY COLLEAGUES TO SERIOUSLY CONSIDER THIS PROPOSAL AS AN IMPORTANT ELEMENT IN ACHIEVING A SUCCESSFUL ECONOMIC RECOVERY AND PLANNING FOR OUR FUTURE INDUSTRIAL SOCIETY.

A SECTION-BY-SECTION ANALYSIS FOLLOWS:

SEC. 1. SHORT TITLE.

SEC. 2. FINDINGS AND PURPOSE.

SEC. 3. APPLICATION OF ANTITRUST LAWS. SPECIFIES THAT NO PERSON SHALL BE HELD LIABLE UNDER FEDERAL AND SIMILAR STATE ANTITRUST LAWS FOR ENTERING A CONTRACT TO CARRY OUT JOINTLY ONE OR MORE RESEARCH AND DEVELOPMENT (R&D) PROJECTS IF SUCH PERSON NOTIFIES THE ATTORNEY GENERAL AND IF SUCH CONTRACT (1) IDENTIFIES AND DESCRIBES THE SCOPE OF EACH R&D PROJECT, (2) SPECIFIES THE OBLIGATIONS OF EACH PARTY TO THE CONTRACT, (3) PROVIDES THAT R&D ACTIVITIES SHALL BE CARRIED OUT THROUGH A MANAGEMENT BOARD CONSISTING OF ONE INDIVIDUAL APPOINTED BY EACH PARTY TO THE CONTRACT, (4) PROVIDES THAT THE MANAGEMENT BOARD SELECTS A CHIEF EXECUTIVE OFFICER WHO MANAGES ALL OF THE R&D ACTIVITIES UNDER THE CONTRACT AND RECOMMENDS OTHER OPERATING CRITERIA, (5) PROVIDES THAT NO NEW PARTY CAN ENTER THE JOINT R&D VENTURE UNLESS SUCH PARTY PAYS A REASONABLE ENTRY FEE, (6) PROVIDES SPECIFIC TITLE, PATENT AND LICENSE RIGHTS, (7) PERMITS EACH PARTY TO PROVIDE, FOR A REASONABLE COMPENSATION, ACCESS TO INDEPENDENT R&D RESULTS AND TO DECLINE, FOR A PERIOD OF THREE YEARS, TO DISCLOSE THE RESULTS OF R&D PROJECTS CARRIED OUT UNDER THE CONTRACT, AND (8) DOES NOT IMPOSE RESTRICTIONS ON OUTSIDE R&D ACTIVITIES.

IMPOSES THE FOLLOWING RESTRICTIONS ON ANY R&D CONTRACT ELIGIBLE FOR EXEMPTION UNDER THIS ACT: (1) THE AGGREGATE SHARE OF THE PARTIES' TO SUCH CONTRACT OF THE RELEVANT MARKET, AS OF THE TIME SUCH CONTRACT IS MADE, FOR RESEARCH AND DEVELOPMENT PROJECTS IN CONNECTION WITH SUCH LINE OF COMMERCE

MAY NOT EXCEED AT ANY TIME 25 PERCENT OF THE RELEVANT MARKET, AS OF THE TIME SUCH CONTRACT IS MADE, FOR ALL RESEARCH AND DEVELOPMENT PROJECTS IN CONNECTION WITH SUCH LINE OF COMMERCE UNLESS (A) THE RESULTS OF SUCH PROJECT ARE NOT LIKELY TO LEAD TO DEVELOPMENT OF INFORMATION OR OF A PRODUCT TO BE MARKETED, (B) THE PARTICIPATION OF ALL THE PARTIES IS (I) NECESSARY FOR THE SUCCESS OF THE PROJECT AND (II) LIKELY TO PRODUCE EFFECTS THAT INCREASE COMPETITION, IMPROVE THE NATIONAL ECONOMY OR FURTHER NATIONAL SECURITY; OR (C) SUCH CONTRACT IS MADE FOR THE PURPOSE OF CARRYING OUT RESEARCH AND DEVELOPMENT ESSENTIAL TO DEVELOP A PRODUCT THAT IS NECESSARY FOR THE PARTIES TO USE TO ACHIEVE COMPLIANCE WITH ANY FEDERAL LAW RELATING TO THE QUALITY OF THE ENVIRONMENT; (2) THE CONTRACT MUST ONLY COVER R&D ACTIVITIES; (3) THE TERM OF ANY CONTRACT CANNOT EXCEED 15 YEARS; (4) THE PARTIES TO THE CONTRACT MUST SUBMIT INFORMATION TO THE ATTORNEY GENERAL AS SPECIFIED IN SECTION 4; AND (5) THE PARTIES TO THE CONTRACT MUST SUBMIT AN ANNUAL VERIFICATION REPORT TO THE ATTORNEY GENERAL.

EXEMPTS FROM DISCLOSURE UNDER SECTION 552 OF TITLE 5, U.S.C., CERTAIN INFORMATION SUBMITTED TO THE ATTORNEY GENERAL UNDER THIS ACT.

SPECIFIES THAT THIS ACT SHALL APPLY TO R&D CONTRACTS IN EFFECT ON OR AFTER THE DATE OF ENACTMENT OF THIS ACT.

SEC. 4. NOTIFICATION OF THE ATTORNEY GENERAL. REQUIRES

THE PARTIES TO ANY CONTRACT TO SUBMIT CERTAIN INFORMATION TO THE ATTORNEY GENERAL REGARDING THE CONTRACT NOT LATER THAN 30 DAYS AFTER MAKING OR AMENDING THE CONTRACT, AS THE CASE MAY BE OR 30 DAYS AFTER THE DATE OF ENACTMENT OF THIS ACT IN THE CASE OF A CONTRACT IN EFFECT ON THE DATE OF ENACTMENT OF THIS ACT.

SEC. 5. INVESTIGATION BY ATTORNEY GENERAL. AUTHORIZES THE ATTORNEY GENERAL TO INVESTIGATE ANY PERSON WHO HAS ENTERED A JOINT VENTURE R&D CONTRACT TO DETERMINE WHETHER THE CONTRACT COMPLIES WITH THE REQUIREMENTS OF SECTION 3 AND THE INFORMATION SUBMITTED UNDER SECTIONS 3 AND 4 IS ACCURATE.

DIRECTS THE ATTORNEY GENERAL TO NOTIFY ANY PERSON WHO IS SUBJECT TO AN INVESTIGATION WHENEVER HE COMMENCES AN INVESTIGATION. DIRECTS THE ATTORNEY GENERAL TO PROVICE WRITTEN NOTICE IF HE FINDS THAT THE CONTRACT DOES NOT COMPLY WITH SECTION 3, INCLUDING (1) A STATEMENT OF FACTS AND REASONS IN SUPPORT OF HIS DETERMINATION, AND (2) A STATEMENT SPECIFYING ANY ACTIONS THAT MAY BE TAKEN TO BRING A CONTRACT IN COMPLIANCE WITH SECTION 3.

EXEMPTS FROM DISCLOSURE UNDER SECTION 552 OF TITLE 5, U.S.C. ANY INFORMATION OBTAINED DURING THE COURSE OF AN INVESTIGATION UNDER THIS SECTION.

SPECIFIES THAT NO DETERMINATION MADE BY THE ATTORNEY

GENERAL UNDER THIS SECTION SHALL BE ADMISSIBLE AS EVIDENCE IN ANY ADMINISTRATIVE OR JUDICIAL PROCEEDING BASED ON A CLAIM ARISING UNDER THE ANTITRUST LAWS.

SEC. 6. DETERMINATION OF ATTORNEY GENERAL. PERMITS THE PARTIES TO ANY CONTRACT TO SUBMIT, NOT LATER THAN 10 DAYS AFTER A CONTRACT IS MADE, A REQUEST TO THE ATTORNEY GENERAL TO DETERMINE WHETHER SUCH CONTRACT IS IN VIOLATION OF THE LIMITATION SPECIFIED IN SECTION 3(B)(1). REQUIRES THAT THE ATTORNEY GENERAL MAKE THE REQUESTED DETERMINATION NOT LATER THAN 60 DAYS AFTER THE RECEIPT OF SUCH REQUEST OR AFTER THE RECEIPT OF ANY ADDITIONAL INFORMATION REQUESTED BY THE ATTORNEY GENERAL. SPECIFIES THAT THE ATTORNEY GENERAL'S DETERMINATION UNDER THIS SECTION IS CONCLUSIVE.

SEC. 7. MODIFICATION OF DAMAGES. SPECIFIES THAT NO PERSON SHALL BE LIABLE UNDER FEDERAL ANTITRUST LAWS FOR AN AMOUNT IN EXCESS OF ACTUAL DAMAGES, THE COST OF SUIT, AND INTEREST AWARDED FROM THE DATE OF JUDGMENT RESULTING FROM UNDERTAKING A CONTRACT RELATING TO A JOINT RESEARCH AND DEVELOPMENT VENTURE.

SEC. 8. ATTORNEY'S FEES. DIRECTS THE COURTS TO AWARD TO A PREVAILING DEFENDENT THE COST OF SUIT, INCLUDING A REASONABLE ATTORNEY'S FEE, IN ANY ACTION BROUGHT UNDER THE ANTITRUST LAWS AGAINST A DEFENDANT WHO IS EXEMPT UNDER THIS ACT.

SEC. 9. STUDY. DIRECTS THE ATTORNEY GENERAL TO SUBMIT A REPORT TO CONGRESS DESCRIBING THE OPERATION OF THIS ACT AND LEGISLATIVE RECOMMENDATIONS NOT LATER THAN 18 MONTHS AFTER THE DATE OF ENACTMENT OF THIS ACT.

SEC. 10. DEFINITIONS.

JH579

98TH CONGRESS
1ST SESSION

H. R. 3393

IN THE HOUSE OF REPRESENTATIVES

Mr. SENSENBRENNER (for himself and ____________) introduced the following bill; which was referred to the Committee on ______

A BILL

To modify the operation of Federal and State antitrust laws for the conducting of certain research and development activities jointly, and for other purposes.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

SHORT TITLE

SECTION 1. This Act may be cited as the ''High Technology Research and Development Joint Venture Act of 1983''.

FINDINGS AND PURPOSE

SEC. 2. (a) The Congress finds the following:

(1) The prosperity and security, as well as the international stature and competitiveness, of the United States depend on the steady growth of its industrial productivity.

(2) Although innovations in some industries have resulted in impressive increases in productivity, the overall rate of growth in industrial productivity in the United States is decreasing.

(3) Growth in industrial productivity requires the strong support of basic research and development and the introduction of advanced concepts, processes, and industries.

(4) In order to maintain the international competitiveness of industries in the United States, it is necessary to facilitate an increase in private research and development.

(5) The most effective Federal actions to encourage long-term private investment in research and development are those actions that remove potential legal barriers

to research and development rather than those actions that intervene directly in commercial markets.

(6) Commercial entities, especially small businesses, are often unable to engage individually in research and development on an efficient scale because of prohibitive costs.

(7) Many desirable research and development projects could be carried out jointly by commercial entities which are willing to share the costs and rewards of such projects.

(8) There is a need to modify the application of the antitrust laws in order to encourage commercial entities to carry out productive research and development projects.

(b) The purpose of this Act is to modify the operation of the antitrust laws and of similar State laws for certain joint research and development projects and thereby encourage commercial entities to carry out, and to secure the benefits of, such projects in order to increase industrial innovation, productivity, and the economic competitiveness of the United States.

APPLICATION OF ANTITRUST LAWS

SEC. 3. (a) No person shall be liable under the antitrust laws, or under any State law similar to the antitrust laws, for attempting to enter into, entering into, or carrying out a contract to which such person is a party if such person gives notice to the Attorney General in accordance with section 4 and if such contract--

(1) provides that the parties to such contract shall carry out jointly one or more research and development projects,

(2) identifies and describes, to the extent practicable, the nature and the scope of each such project, and the manner in which such project will be carried out,

(3) specifies with respect to each party to such contract the obligations applicable to such party,

(4) provides that such contract shall be carried out through a management board consisting of one individual appointed by each party to such contract to represent such party, which shall submit to the parties to such contract recommendations regarding initiating or terminating any research and development project, after taking into account--

(A) the importance of such project to the domestic economy or national defense,

(B) the long-run needs of the United States industries represented by the parties to such contract,

(C) the specific needs of each such party, including the risks and costs for the individual parties to undertake such project, and

(D) the educational and intellectual value of such project,

(5) provides that such management board shall select a chief executive officer who shall--

(A) manage all of the research and development projects to be carried out under such contract,

(B) submit to the parties to such contract recommended criteria to be applied to determine whether such contract should be amended to allow another person to become a party to, or to allow any party to withdraw from, such contract, and

(C) submit to such parties recommended criteria to be applied to determine whether and under which terms any license should be granted to use any information or product resulting from a research and development project carried out under such contract and, in formulating such criteria, shall encourage the widest possible dissemination of such information or product, giving due regard to the risks assumed and the resources expended by the parties to carry out such project,

(6) provides that no other person shall become a party to such contract, other than by succession in

interest, unless such person pays to all such parties jointly, not less than a reasonable amount based on the cost and the value of the research and development projects then being carried out under the contract,

(7) provides that--

(A) applications for patents on patentable products discovered in the course of carrying out research and development projects under such contract shall be made by such parties, and such parties shall retain title to all inventions, patents, and information resulting from such projects,

(B) each party to such contract at the time information or a product is discovered or developed shall at such time be entitled to irrevocable, nonexclusive, and equivalent licenses to all patents obtained by such parties for such information or product,

(C) each party shall be entitled to use the results of each research and development project carried out under such contract, in a manner which bears an equitable relationship to the risks such party assumed, which use may include--

(i) exclusive access to such results for not to exceed 3 years,

(ii) royalty-free licenses or licenses at royalty rates which reflect the risks assumed and resources expended by such party, and

(iii) a share of any royalties collected from nonparties,

(D) not later than 3 years after such parties receive such licenses, licenses shall be made available to any other domestic person on such reasonable terms as such parties may establish, and

(E) each of such parties shall collect on behalf of all of such parties royalties for the use of information or products resulting from any such project and may retain such proportion of the revenues as may be agreed to by such parties,

(8) permits each of such parties--

(A) to provide, for a reasonable compensation, access to such research and development projects, other than research and development projects carried out under such contract, as is necessary for such parties to carry out research and development projects under such contract,

(B) to decline, for a period of 3 years, to disclose the results of research and development projects carried out under such contract,

(C) assign employees to carry out research and development projects under such contract, and

(D) undertake under such contract, on behalf of all of such parties, a particular aspect of research and development,

(9) does not impose on any such party--

(A) any restriction with respect to any research and development project, other than a research and development project to be carried out under such contract, which may be carried out by such party,

(B) any obligation to make available to any other person the results of any research and development project, other than a research and development project carried out under such contract, carried out by such party, or

(C) any restriction or requirement, other than a restriction or requirement permitted under this section, on the exercise of any right such party may have to exploit the inventions or use any information or product resulting from a research and development project carried out under such contract, and

(10) does not violate any limitation specified in subsection (b).

(b) For purposes of subsection (a)--

(1) with respect to all the research and development

projects being or to be carried out, under a contract, in connection with a line of commerce, the aggregate share of the parties to such contract of the relevant market, as of the time such contract is made, for research and development projects in connection with such line of commerce may not exceed at any time 25 percent of the relevant market, as of the time such contract is made, for all research and development projects in connection with such line of commerce unless--

(A) the results of such projects are not likely to lead to development of information or of a product to be marketed,

(B) the participation of all the parties is--

(i) necessary for the success of such projects, and

(ii) likely to produce effects that increase competition, improve the national economy, or further national security, or

(C) such contract is made for the purpose of carrying out research and development essential to develop a product that is necessary for the parties to use to achieve compliance with any Federal law relating to the quality of the environment,

(2) such contract, and any other agreement relating

to such contract, may not provide that any of the parties shall carry out jointly or severally any activity other than--

(A) a research and development project,

(B) any activity necessary to carry out the contract terms specified in subsection (a) and the requirements of this subsection, and

(C) any activity necessary to obtain a patent or issue a license applicable to the information or product resulting from a research and development project carried out under such contract,

(3) the term of such contract may not exceed 15 years,

(4) the parties to such contract shall submit to the Attorney General information in accordance with section 4, and

(5) such parties shall submit a report annually to the Attorney General verifying that the contract as then in effect complies with this section, and containing any additional information necessary to keep current the information required to be submitted in accordance with section 4.

(c) Any information submitted to the Attorney General for purposes of making a determination under subsection (b)(1), by a party, or by a person proposed to become a party, to such contract shall be exempt from disclosure under section 552 of title 5, United States Code.

(d) This Act shall apply with respect to research and development projects carried out under contracts in effect on or after the date of the enactment of this Act.

NOTIFICATION OF ATTORNEY GENERAL

SEC. 4. (a) Not later than 30 days after making a contract or after amending a contract, as the case may be, or 30 days after the date of the enactment of this Act in the case of a contract in effect on such date of enactment, with respect to which any benefit under this Act is or may be claimed, the parties to such contract shall submit in writing to the Attorney General, in such form as the Attorney General may require--

(1) notice of the date that such contract is made, and of the date of any amendment to such contract,

(2) the name of each of the parties to such contract,

(3) a description of each research and development project to be carried out under such contract,

(4) with respect to each such research and development project, the name of each party who will participate in carrying out such project, and

(5) any other information, required by rules issued by the Attorney General, necessary to determine if such

contract complies with section 3.

(b) Information submitted to the Attorney General under subsection (a) shall be made available to the public in accordance with section 552 of title 5, United States Code.

INVESTIGATION BY ATTORNEY GENERAL

SEC. 5. (a) The Attorney General may investigate persons who are required to submit information under section 4, for the purpose of determining whether--

(1) such information is submitted, is accurate when submitted, and is kept current,

(2) the annual reports submitted under section 3(b)(5) are accurate,

(3) the contract with respect to which such reports are submitted complies with section 3, and

(4) the research and development projects carried out under such contract comply with the terms of such contract and are consistent with the descriptions of such projects provided to the Secretary under section 4.

(b) Whenever the Attorney General commences an investigation under subsection (a), the Attorney General shall notify the person who is subject of such investigation that such investigation is in progress. If the Attorney General determines with respect to the contract involved in the investigation that such contract, or the contract as amended, does not comply with section 3, then the Attorney

General shall give written notice of such determination to the parties to such contract. Such notice shall include--

(1) a statement of the facts and reasons in support of such determination, and

(2) a statement specifying any actions that such parties may take to modify such contract to comply with section 3.

(c) Information obtained by the Attorney General in the course of conducting any investigation under this section is exempt from disclosure under section 552 of title 5, United States Code.

(d) No determination made by the Attorney General under subsection (a) shall be admissible as evidence in any administrative or judicial proceeding based on a claim arising under the antitrust laws.

DETERMINATION OF ATTORNEY GENERAL

SEC. 6. (a) Not later than 10 days after a contract to carry out one or more research and development projects jointly is made, the parties to such contract may submit to the Attorney General a request that the Attorney General determine whether such contract violates the limitation specified in section 3(b)(1). Such parties shall submit to the Attorney General such information as the Attorney General may request for purposes of making such determination.

(b) Not later than 60 days after the Attorney General receives a request for a determination or after the receipt of any information requested by the Attorney General, whichever occurs later, under subsection (a), the Attorney General shall make, and notify the parties of the results of, such determination. Notwithstanding the preceding sentence, the Attorney General shall make such determination not later than 120 days after receiving a request for such determination.

(c) Information obtained by the Attorney General in the course of making any determination under this section is exempt from disclosure under section 552 of title 5, United States Code.

(d) In any action under the antitrust laws or any State law similar to the antitrust laws, a determination made under this section shall be conclusive as to whether the contract involved violates the limitation specified in section 3(b)(1).

MODIFICATION OF DAMAGES

SEC. 7. No person shall be liable under the antitrust laws for an amount in excess of the actual damages sustained by the claimant by reason of the violation of any such law, the cost of suit (including a reasonable attorney's fee), and any interest awarded (from the date of judgment) with respect to such damages if such liability arises from attempting to make, making, or performing a contract to carry out a research and development program jointly with another person.

ATTORNEY'S FEES

SEC. 8. In any action under the antitrust laws brought against a defendant who is not found, by reason of the operation of this Act, liable with respect to a claim in such action, the court shall award to the prevailing defendant the cost of suit, including a reasonable attorney's fee, attributable to defending against such claim.

STUDY

SEC. 9. Not later than 18 months after the date of the enactment of this Act, the Attorney General shall submit to the Speaker of the House of Representatives and the President pro tempore of the Senate a report describing the operation of this Act and including any recommendations of the Attorney General relating to any legislation necessary or appropriate to achieve the purpose of this Act.

DEFINITIONS

SEC. 10. For purposes of this Act--

(1) the term ''antitrust laws'' shall have the meaning given it in subsection (a) of the first section of the Clayton Act (15 U.S.C. 12(a)), except that such term shall include section 5 of the Federal Trade

Commission Act (15 U.S.C. 45) to the extent that such section 5 relates to unfair methods of competition,

(2) the term ''Attorney General'' means the Attorney General of the United States,

(3) the term ''person'' shall have the meaning given it in subsection (a) of the first section of the Clayton Act (15 U.S.C. 12(a)),

(4) the term ''product'' means any goods or services,

(5) the term ''research and development project'' means an activity primarily involving--

(A) theoretical analysis, systematic study, exploration, or experimentation,

(B) the conduct of activities designed or intended to lead to the ultimate utilization of analytical results for the development of a particular application or product,

(C) the systematic application of knowledge through the conduct of activities designed to solve a particularly defined technical problem in order to achieve proof of principle or technical feasibility, or

(D) the extension of investigative findings and theories of a scientific or technical nature into practical application for experimental and pilotscale demonstration purposes, up to the stage of industrial application, including the production, testing and licensing of models, devices, equipment, materials, and processes, and

(6) the term ''State'' shall have the meaning given it in section 4G(2) of the Clayton Act (15 U.S.C. 15g(2)).

CONGRESSIONAL BUDGET OFFICE
U.S. CONGRESS
WASHINGTON, D.C. 20515

Alice M. Rivlin
Director

July 13, 1983

Honorable Marilyn Lloyd, Chairman
Subcommittee on Energy Research
and Production
Committee on Science and Technology
U.S. House of Representatives
Washington, D.C. 20515

Dear Mrs. Lloyd:

In your letter of June 28, you raised several questions related to the hearings of June 22 before the Subcommittee on Energy Development and Applications and the Subcommittee on Energy Research and Production. My responses to these questions are enclosed with this letter. Should you have any further inquiries concerning these issues, I would be happy to address them.

With best wishes,

Sincerely,
Nancy Anderson
for
Alice M. Rivlin
Director

Enclosure

Lower Oil Prices: Implications for Energy R&D Policy
Responses of Dr. Rivlin to Questions Submitted by
The Subcommittee on Energy Development and Applications
and
The Subcommittee on Energy Research and Production

1. **In your testimony, you mention that an oil import fee could be as effective at reducing oil imports as an energy R&D program? Isn't an oil import fee an expensive device for accomplishing that goal?**

A. An oil import fee would certainly have macroeconomic costs. We estimate that it would lower real GNP by about 0.1 percent for each dollar of fee. But such a fee might have more pronounced effects on the demand for oil imports. For example, we estimate that a $5 fee would reduce U.S. oil consumption by about a quarter of a million barrels per day after one year, and by greater amounts in later years. An R&D program cannot provide as rapid a reduction in oil demand. In the long-term, an oil import fee and the energy R&D program are very complementary. The R&D program would diversify society's technological options for replacing oil imports, while an oil import fee would increase our incentives to draw upon those options.

2. **What sort of expenditures do we now expect to occur in the synfuels program, and what will determine this level?**

A. CBO's time horizon for budget analysis is five years, so that we now have no estimates extending beyond 1988. Because of the long lead time connected to synfuels projects, we do not expect significant outlays to be made by the Synfuels Corporation through 1988. Beyond that, estimates of synfuels expenditures are highly speculative; their level will depend on trends in oil prices, the level of the Synfuels Corporation's guarantees, and the form taken by those guarantees. Given present forecasts of oil price trends, however, there is a strong potential that the government will incur major expenses through this program, particularly if price guarantees rather than loan guarantees predominate.

3. **What if your oil price forecasts are wrong and prices resume the high growth rates once projected for them? Shouldn't we continue a synfuels development program as "insurance" against this possibility?**

A. There is always potential for error in economic forecasting, and this is particularly true when economic conditions are dependent on political factors, as is the case in the oil market. This potential represents a risk, and the synfuels program can be viewed as an "insurance" policy serving to lower this risk. Congress must still decide, however, whether or not this insurance policy is worth its cost, or whether the funding devoted to the development program might bring greater benefits in other areas. Synthetic fuels may indeed be an important part of the response to a future oil disruption. But it is unclear whether a large-scale development program would be a more cost-effective means of preparation than a strong technology program coupled with use of the Strategic Petroleum Reserve.

4. **Could you briefly describe the basis on which you disaggregate federal R&D funding into basic research, applied research, and development?**

A. R&D activities are traditionally broken down into the categories of basic research, applied research, and development. Together, these categories describe a spectrum of scientific and engineering activities. Basic research refers to fundamental scientific investigation, undertaken without regard to commercial applications. Applied research refers to similar scientific work carried out with specific practical objectives in mind. Finally, development refers to the actual transformation of scientific insights into viable products and processes.

These categories are first approximations concerning the mix of funding priorities and thus are useful indicators of overall trends in federal support for R&D. Nevertheless, it should be pointed out that allocating activities among these categories can be highly subjective. Basic research is easily distinguished from development, but the intermediate category of applied research contains elements of both. Hence, these general categories provide only a first step for actually assessing government activity. As is true for many R&D issues, one has to look beyond the general categories to evaluate the economic significance of spending patterns.

5. **You mentioned that the government has a poor record when it comes to selecting technologies for commercial development. Could you give us some examples? What are the reasons this record is so poor?**

A. First, let me stress that I was referring to government funding of commercially oriented development. In areas where the government is the prime or sole purchaser--for instance, in defense or space exploration--the government's record appears to be fairly good. This is probably because in such cases the government has a clear understanding of the performance required of the technology being funded. In commercially oriented ventures, however, the government has no such expertise.

There are many instances in which the government's efforts to sponsor the development of specific technologies have led to poor results. Most recently, HUD attempts to commercialize modular housing technologies (Operation Breakthrough in the early 1970's) had little impact. In the automobile industry, the government sought to promote innovation through the CARP program in the late 1970's, but this effort never attracted significant industry support, so that it quickly became a casualty of budgetary pressures in the early 1980's. Many government development initiatives in the energy area--ocean thermal systems and wind energy, for example--have failed to attract private support. Evidence from abroad also suggests that governments are poorly suited to pick technological winners: the Concorde SST is probably the foremost example of this.

There are, of course, examples of successful government sponsorship of commercially oriented R&D--in agriculture, for instance. But successful government funding of development has generally been linked to government purchases. This is the case for defense support of semiconductors, for instance.

Faced with this mixed record, it is difficult to draw general conclusions about how to improve commercial development. One implication seems to be that government funding is unlikely to bear fruit unless a program also enjoys significant support in the private sector. The government is ill-suited to dictate the development of commercial technologies. Secondly, the underlying technological opportunity is crucial; if an industry's scientific base is poor, government funding of development is likely to produce poor results. Thirdly, government development efforts must reflect an awareness of the institutional features (industrial relations and market structure, for instance) of an industry and how these relate to the technology being considered. Our historical experience appears to tell us more about the problems and prospects of specific industries than about the general principles that should guide government programs.

6. **You mentioned that it might be more appropriate to focus on anti-trust issues than direct federal funding to encourage private sector research. Do you believe that the approach stipulated in H.R. 3393 will address the problems in anti-trust that you perceive?**

A. Anti-trust regulations make up part of the institutional setting that affect the behavior and performance of U.S. firms--including their research and development activities. As such, shifts in anti-trust policy are one of the policy tools that can be used to affect R&D and the innovation process.

One of the most significant features of economic innovation--a process that is not well understood--is the great diversity of factors that affect it. Different technologies and different industries face different obstacles to innovation. This implies that specific and targeted policies will be more appropriate than very general ones (for example, across-the-board increases in R&D funding or general anti-trust relief).

Flexible anti-trust policies are likely to be especially useful under circumstances such as the following: where the costs of research are very high, where adequate competitive pressures are provided by foreign competition, and where the R&D is related to reducing the social costs reflected in government regulations. It is important to ensure, however, that the relaxation of anti-trust rules does not weaken the competitive forces within an industry, since the spur of competition is probably the most significant inducement to technological innovation.

Given the specific character of the factors affecting technological performance in different industries, it is unlikely that a single bill could address all of the problems connected with the technological effects of anti-trust regulations. H.R. 3393 is too complex a piece of legislation to be discussed adequately in this context. However, it does appear suited to the requirements of technological innovation in the so-called high-tech industries, since it balances the competing concerns of encouraging technological risk-taking, safeguarding competitive pressures, and providing administrative flexibility. Should the Committee wish a fuller analysis of this bill and the issues it addresses, CBO would be happy to look into it in more depth.

DON FUQUA (Fla.), Chairman

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COMMITTEE ON SCIENCE AND TECHNOLOGY
SUITE 2321 RAYBURN HOUSE OFFICE BUILDING
WASHINGTON, D.C. 20515
(202) 225-6371

LARRY WINN, JR., KANS.
MANUEL LUJAN, JR., N. MEX.
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Minority Staff Director

June 28, 1983

Dr. Eric Willis
Director of Research
International Energy Agency
Paris, France

Dear Dr. Willis:

We want to thank you for your excellent testimony before the Subcommittee on Energy Development and Applications and the Subcommittee on Energy Research and Production on June 22 on the subject of lower oil prices and their implications for energy research and development policy. We would like to supplement the record of the hearing with some additional questions on this topic.

We appreciate your cooperation on this matter. If you have any questions regarding this request, please contact Dr. Harlan Watson of the staff of the Subcommittee on Energy Development and Applications at (202) 225-4320.

Sincerely,

DON FUQUA, Chairman
Subcommittee on Energy
Development and Applications

Marilyn Lloyd
MARILYN LLOYD, Chairman
Subcommittee on Energy
Research and Production

DF/ML:Wba
Enclosure

Lower Oil Prices: Implications for Energy R&D Policy
Additional Questions for Dr. Willis

1. To what extent is the current Administration's R&D investment strategy shared by other IEA governments? Do they tend to limit expenditures on R&D to long-run, high-payoff ventures which industry could not be expected to undertake on their own?

2. In which areas of energy R&D do you expect international cooperation to play an increasingly important role?

3. To the extent that industry contributions to energy R&D can be measured, how does the level of the U.S. private sector contribution compare relative to that for the other IEA members?

Lower Oil Prices: Implications for Energy R&D Policy
Additional Questions for Dr. Willis

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2. In which areas of energy R&D do you expect international cooperation to play an increasingly important role?

3. To the extent that industry contributions to energy R&D can be measured, how does the level of the U.S. private sector contribution compare relative to that for the other IEA members?

Question 1

Other IEA countries do not generally share the perception of the current Administration that government should not become involved in demonstration activities leading to commercialisation. This is particularly true of Japan and Germany, among our foremost competitors. However, recessionary forces are curtailing investments by sheer necessity, so that fewer high cost commercialisation type projects will be built in these countries as a result. Few countries ideologically limit their expenditures to the so-called high-risk, high pay-off, long-term ventures.

Question 2

The most promising avenues for international cooperation are in the conservation, renewable energy areas plus the long range activities such as fusion energy and basic energy sciences. However, there is some resistance to cooperation where proprietary rights and patents become involved. Commercial considerations and advantage then become important.

In the IEA, current trends show a marked increase in fusion energy projects and agreements. Besides interest in the proposed Fusion Irradiation Test Facility, there are the large coil experiments, Stellarator, Textor and cooperative projects as well as a cooperative agreement to share the results and experiences of the three large tokomaks, i.e., JET (Europe), JT-60 (Japan) and TFTR (U.S.). Fusion energy is expensive and long range, thus making international cooperation almost an imperative. Furthermore, it has not yet progressed to the point where commercial advantage considerations are inhibitors to cooperation. In the basic energy sciences, coal science generally, and coal combustion in particular, are drawing very enthusiastic responses to proposed agreements.

If the commercialisation of breeder technology is further delayed, this costly enterprise will find more ready partners overseas to share costs and benefits. Under these circumstances, the US tax payers' dollar can be highly leveraged. It can be plain good business to approach international ventures in this light.

Question 3

The extent of industry contributions to energy R&D are very difficult to measure. For this reason the contention that industry is almost automatically and naturally picking up the short term R&D from government is, in most instances, unsubstantiated by hard data. Nevertheless, we have managed to accummulate some industrial data which are submitted herewith with the caveat that they are the best approximation available to us. The U.S. industrial sector comparisons may be judged from the following Tables.

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SUITE 2321 RAYBURN HOUSE OFFICE BUILDING
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(202) 225-6371

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General Counsel

DAVID S. JEFFERY
Minority Staff Director

June 28, 1983

Mr. Joel Darmstadter
Resources for the Future
1755 Massachusetts Avenue, N.W.
Washington, D. C. 20036

Dear Mr. Darmstadter:

We want to thank you for your excellent testimony before the Subcommittee on Energy Development and Applications and the Subcommittee on Energy Research and Production on June 22 on the subject of lower oil prices and their implications for energy research and development policy. We would like to supplement the record of the hearing with some additional questions on this topic. Also included are a number of questions submitted by minority Members of the Subcommittees.

We appreciate your cooperation on this matter. If you have any questions regarding this request, please contact Dr. Harlan Watson of the staff of the Subcommittee on Energy Development and Applications at (202) 225-4320.

Sincerely,

Marilyn Lloyd

DON FUQUA, Chairman
Subcommittee on Energy
Development and Applications

MARILYN LLOYD, Chairman
Subcommittee on Energy
Research and Production

DF/ML:Wba
Enclosure

Lower Oil Prices: Implications for Energy R&D Policy
Additional Questions for Mr. Darmstadter

1. What general principles should guide the federal energy R&D program?

2. You suggest in your testimony that we might want to rethink ambitious synfuel production targets in favor of different objectives over a different time scale. What might be some examples of these "different objectives"?

3. You note that it is desirable to have an energy R&D strategy based on some degree of risk aversion. What do you mean by this? Do you mean that we should be pursuing a variety of energy options?

4. In your testimony you state that the energy/GNP ratio fell at an average rate of 2 1/2 percent annually between 1973 and 1981. Yet you note that the most recent studies taken together are forecasting a long-term energy/GNP ratio decline of a little over 1 percent annually. Why should we expect such a slowdown in increasing our energy productivity?

Resources for the Future
1755 Massachusetts Avenue, N.W.
Washington, D.C. 20036

July 8, 1983

Honorable Don Fuqua ✓
Honorable Marilyn Lloyd
Subcommittee on Energy
Research and Production
Suite 2321 Rayburn House Office Building
Washington, DC 20515

Dear Representatives Fuqua and Lloyd:

In response to your letter dated June 28, 1983, requesting some additional views in connection with the hearing of June 22, I enclose herewith brief answers to the four questions which you posed.

I hope this further amplification will be helpful to you in rounding our the hearing record.

Sincerely,

Joel Darmstadter

Joel Darmstadter
Senior Fellow, Center for
Energy Policy Research

Enclosure
JD/mmk

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AND TECHNOLOGY

202/328-5000 *Cable: Resources*

1. What general principles should guide the federal agency R&D program?

A succinct statement is difficult, but in general the government's R&D role is best applied to areas that have a long gestation period, involve a high risk of failure but a substantial payoff from success, and reflect a sharp divergence between the accrual of benefits and the incidence of costs. (Private firms, for example, are unlikely to invest heavily in developing production processes designed primarily to clean up the air for society as a whole.) Clearly, in the spectrum from basic research to commercialization, the government's role becomes progressively less appropriate and that of industry increasingly indispensable.

2. You suggest in your testimony that we might want to rethink ambitious synfuel production targets in favor of different objectives over a different time scale. What might be some examples of these "different objectives"?

To the extent possible, the strategy adopted should aim at being the most efficient, least costly, and least harmful to the environment and local communities. There is some question whether the pursuit of large, near-term production targets might not compromise one or more of these goals. A less threatening world oil market, strengthened protections against disruptions, and slower energy-demand growth may permit some relaxation of these near-term objectives. Instead, proportionately greater importance might be given to a synfuels program emphasizing information, insurance and diversity of experience and technology rather than maximization of fuel availability.

3. You note that it is desirable to have an energy R&D strategy based on some degree of risk aversion. What do you mean by this? Do you mean that we should be pursuing a variety of energy options?

We cannot foreclose the re-assertion of OPEC market power or of foreign disruption. Nor can we rule out unpleasant surprises of a technical or environmental nature in the operation of different energy systems. These uncertainties justify pursuit of a broad range of energy options and policies.

4. In your testimony you state that the energy/GNP ratio fell at an average rate of 2 1/2 percent annually between 1973 and 1981. Yet you note that the most recent studies taken together are forecasting a long-term energy/GNP ratio decline of a little over 1 percent annually. Why should we expect such a slowdown in increasing our energy productivity?

The dramatic reduction in the energy/GNP ratio during the past decade appears to have been triggered primarily by extraordinarily sharp increases in real energy prices. Future price escalation may be more moderate. Some reduction in energy intensity may have been achieved through one-time improvements in operating practices ("housekeeping"). For both reasons, it seems prudent to assume continuation in enhanced energy productivity, but at a lesser rate than heretofore.

DON FUQUA (Fla.), Chairman

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J. H. POORE
Executive Director

ROBERT C. KETCHAM
General Counsel

DAVID S. JEFFERY
Minority Staff Director

June 28, 1983

Dr. Daniel E. Dreyfus
Division Director
Strategic Analysis and Energy Forecasting
Gas Research Institute
1019 19th Street, N.W., Suite 910
Washington, D.C. 20036

Dear Dr. Dreyfus: Dan

We want to thank you for your excellent testimony before the Subcommittee on Energy Development and Applications and the Subcommittee on Energy Research and Production on June 22 on the subject of lower oil prices and their implications for energy research and development policy. We would like to supplement the record of the hearing with some additional questions on this topic.

We appreciate your cooperation on this matter. If you have any questions regarding this request, please contact Dr. Harlan Watson of the staff of the Subcommittee on Energy Development and Applications at (202) 225-4320.

Sincerely,

DON FUQUA, Chairman
Subcommittee on Energy
Development and Applications

Marilyn Lloyd
MARILYN LLOYD, Chairman
Subcommittee on Energy
Research and Production

DF/ML:Wba
Enclosure

Lower Oil Prices: Implications for Energy R&D Policy
Additional Questions for Dr. Dreyfus

1. What general principles should guide the federal energy R&D program?

2. Given the change in outlook, is it still a wise use of the taxpayers' money to accelerate the commercialization of synfuels? Do you think that the Synthetic Fuels Corporation should proceed as it was originally envisioned, or should it turn to an R&D orientation?

3. If GRI's R&D budget was sufficiently large, would the Great Plains Coal Gasification Project be a good R&D investment for GRI?

4. As we understand it, GRI member companies include interstate pipelines, distribution companies, publicly owned utilities, plus several associate members, but lacks significant membership from the production side. Has thought been given to expanding membership to include more natural gas producers and if this happened, how would it change the character of GRI's R&D program?

5. Do you have any indication of the dollar payback the gas industry is receiving per dollar of GRI research investment? Is it $0.50, $1, $5, $10, or what?

6. Has the recent world oil price situation affected the GRI R&D programs, and if so, how? What are the implications for the federal energy R&D program?

GRI
gas research institute

1019 19th Street, N.W.
Suite 615
Washington, D.C. 20036
202/785-3409

DANIEL A. DREYFUS
Director
Energy Forecasting and Analysis

July 7, 1983

The Honorable Don Fuqua
Chairman
Subcommittee on Energy
Development and Applications
Committee on Science and Technology
U.S. House of Representatives
2321 Rayburn Office Building
Washington, DC 20510

Dear Mr. Chairman:

This is in response to the letter of June 28 from you and Chairman Lloyd transmitting supplemental questions relating to the joint subcommittee hearing of June 22 on the impact of low oil prices.

Enclosed are my responses to the supplemental questions. I appreciated the opportunity to appear at the hearing and am glad to offer this additional material. Sustaining a strong program for energy technology development through these times of severe budget constraints and the restructuring of energy supply and demand is a challenge which deserves Congressional attention. The continuing interest of your committee is important to the energy industries and the general public.

Sincerely,

Enclosure

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AND TECHNOLOGY

Gas Research Institute, 8600 West Bryn Mawr Avenue, Chicago, Illinois 60631 312/399-8100

RESPONSE OF DR. DANIEL A. DREYFUS
TO SUPPLEMENTAL QUESTIONS

For the record of the June 22, 1983, joint hearing before the Subcommittee on Energy Development and Application and the Subcommittee on Energy Research and Production on the subject of Lower Oil Prices: Implications for Energy R&D Policy.

Question #1

What general principles should guide the federal energy R&D program?

Response

In general, federal support or direct action in energy R&D should be provided for research which is long-term and high-risk in nature and which has the potential to provide benefits to a broad public.

In specific instances, however, there can be compelling reasons to deviate from the general rule. Federal support for desirable shorter-range energy R&D or for R&D having more narrow beneficiary groups may be justified in the following situations:

- Where industrial R&D cannot serve the purpose, because costs exceed the financial capability of the available sponsors or because there is no way for industry to capture a financial return from the R&D.
- Where industrial R&D would lack credibility, such as research establishing the health, safety, and environmental impacts of industrial activities.
- Where there is a strong public interest need which is not translated into an economic incentive for potential industrial sponsors. For example, national security or the maintenance of a level of expertise and advancement in general technological areas where the immediate applications are not always self evident, i.e., cryogenics, metallurgy, materials.

Question #2(a)

Given the change in outlook, is it still a wise use of the taxpayers' money to accelerate the commercialization of synfuels?

Response

As the Committee is aware, the history of federal involvement in synthetic fuels stems from mixed objectives. Three distinct justifications have been offered for a federal synfuels program:

1. That synfuels are inherently more economical than conventional petroleum-based fuels once the technologies are proven, but because there is no established industry and the introductory risk is high, temporary federal incentive and support programs will be required to commercialize the technologies.

2. That synfuels will remain more costly than conventional alternatives, but economic and national security threats from dependence upon unreliable foreign oil sources justify long-term federal support for improvement of synfuels technologies and continuing subsidization of some measure of productive capacity.

3. That only commercial-sized demonstrations will establish the real economic, social and environmental costs associated with the conversion of domestic coal and shale into liquid and gaseous synfuels and that the importance of measuring the cost of this option warrants federal support for a limited number of commercial-sized plants.

When Congress established the Synthetic Fuels Corporation, proponents cited each of these justifications. The House measure, which was appended to amendments to the Defense Production Act clearly emphasized the second or "national security" justification. The original Senate initiative was a very modest proposal probably emphasizing the third or "policy-making information" justification. President Carter's initiative called for a very large program predicated on the first assumption that the synfuels industry would ultimately become an economically competitive venture.

At the time, the widespread belief that world oil prices would escalate much more than general inflation led many people to the conclusion that synfuels would eventually be at least marginally competitive with conventional alternatives. Many industry-sponsored synfuels initatives were based upon this assumption.

The current belief that oil prices will be stable has cast doubt upon the ability of federal incentives to launch a self-sustaining industry. The current world over-supply of oil similarly has diminished enthusiasm for the national security justification.

The fact, of course, is that there is no greater certainty of stable oil prices than there formally was of continuing price escalation, and that most of the current supply surplus remains in insecure areas of the world.

In my own view, it seems inevitable that another situation will arise in this century in which the option of conversion of domestic shale, coal, and other resources to synthetic gas and liquids will become an important public policy issue. I believe that judgments about the real costs of a large synfuels industry are unknown today and will remain unknown until a few diversified commercial sized plants are in operation in the United States. I believe that the intangible costs associated with bad policy decisions predicated upon guesswork could easily be far more costly than a few synfuel plants. The "information" justification alone is more than adequate to warrant the currently authorized program of the Synthetic Fuels Corporation, whatever one might believe about the future of world oil.

Question #2(b)

Do you think that the Synthetic Fuels Corporation should proceed as it was originally envisioned, or should it turn to an R&D orientation?

Response

The Synthetic Fuels Corporation was deliberately designed by the Congress to complement rather than duplicate the ongoing synethetic fuels R&D program of the Department of Energy, which at the time was quite large but had shown an incapability or reluctance to carry ventures to the commercial stage. The synfuels corporation concept was overtly based upon a banking or financial model. That is, technical judgments and management were to be based upon the secondary evidence of the proponents' willingness and ability to share risk, rather than upon independent scientific and engineering studies.

The corporation was given no function except commercialization to assure that it would not repeat the Department's predilection to continue multiple experiments and avoid major commitments.

The Corporation, therefore, has no fundamental capability to conduct an R&D program. The only reason to assign that function to it would be to divert its existing budget authority into R&D.

Question #3

If GRI's R&D budget was sufficiently large, would the Great Plains Coal Gasification Projection be a good R&D investment for GRI?

Response

There are many institutional factors wich complicate a simple answer to this question. The concept of GRI, aside from budget considerations, does not easily accommodate a venture which is primarily a system-specific gas supply project. The regulatory complications relating to both the project and GRI's purpose defy description.

In a purely technical sense, however, the experience and information which will be gained from the completion and operation of the Great Plains Project will be of tremendous value to the gas industry and to the general national public.

The project, thus far, has had a good construction record in terms of costs and schedule. It can provide a valid experience with gasification in a real system management context which can help put the technology into perspective as a long-term supply supplement. Completion and operation of the project can provide the opportunities to deal with the many institutional issues facing the synfuels option. Much of the learning experience, both technical and non-technical will be directly applicable to liquid fuel oriented projects as well.

There is abundant justification to complete and operate the project from a public policy point of view. Harking back to question #1, it is not clear that the capability to insure completion exists without further federal aid.

Question #4

As we understand it, GRI member companies include interstate pipelines, distribution companies, publicly owned utilities, plus several associate members, but lacks significant membership from the production side. Has thought been given to expanding membership to include more natural gas producers and if this happened, how would it change the character of GRI's R&D program?

Response

The GRI concept is, of course, shaped by the structure of the natural gas industry and the history of GRI's creation. Not only its corporate membership, but its heavy dependence upon funding through the FERC approval and the regulatory structure is associated with the regulated segment of the gas industry.

Of course, several of GRI's member companies do have production affiliates, but adding independent unregulated companies to the membership would involve a significant departure from the current concept.

GRI does carry out R&D in unconventional natural gas resources. Such R&D clearly benefits both the member companies and their ratepayers. Not only is security of supply a principal objective in an industry R&D program, but the ability to increase the economic natural gas resource base through improvements in conventinal gas technologies promises to decrease the average price of gas to all consumers.

GRI has acted to involve the producer segment of the industry in this work through cofunding arrangements and hopes to expand the level of such activities. If producers were more directly involved as GRI members, the direction of the supply R&D would very probably remain the same. The level of activity might increase only as a result of increased total funding.

Question #5

Do you have any indication of the dollar payback the gas industry is receiving per dollar of GRI research investment? Is it $0.50, $1, $5, $10, or what?

Response

Attached is a summary of testimony presented by GRI before the Oklahoma Corporation Commission which discusses the benefits of the GRI program.

Question #6

Has the recent world oil price situation affected the GRI R&D programs, and if so, how? What are the implications for the federal energy R&D program?

Response

As I pointed out in my testimony, GRI still projects oil prices to increase at an annual rate of about 2% greater than inflation over the long run. The recent oil price reductions, however, do result in more competitive prices for petroleum products in any particular future year.

GRI's R&D strategy was already heavily oriented toward increased end use efficiency for gas and reduction in gas supply costs. It remains appropriate, therefore, for the intensified competition posed by a lower oil price outlook.

The Administration's decision to reduce federal support for near-term R&D directed at petroleum back-out and the de-emphasis of synthetic fuels R&D pre-dated the oil price reductions. In my judgment, the current complacency about future oil supply and price stability will only intensify resistance to efforts to sustain or reinstate these programs.

Attachment

BEFORE THE CORPORATION COMMISSION
OF THE STATE OF OKLAHOMA

Oklahoma Natural Gas Company — Cause No. 28069

IN THE MATTER OF APPLICATION)
OF OKLAHOMA NATURAL GAS COMPANY)
FOR AN INCREASE IN ITS RATES,)
CHARGES FOR GAS SERVICE AND)
OTHER APPROPRIATE RELIEF)

SUMMARY
OF
DIRECT TESTIMONY
OF
DR. ROBERT B. ROSENBERG AND ATTACHMENTS

My name is Robert B. Rosenberg, and I am employed by Gas Research Institute (GRI) as Executive Vice President. The purpose of my testimony is to support the proposal by Oklahoma Natural Gas Company (ONG) to include GRI's funding unit of 7.2 mills per Mcf in its utility operating expense calculations for rate-making purposes by providing information concerning GRI and demonstrating that GRI's research and development (R&D) activities are beneficial to the consumers of natural gas in the state of Oklahoma.

GRI is a not-for-profit scientific institution formed in 1976, which plans, manages, and develops financing for a cooperative, national R&D program for the mutual benefit of the gas industry and its present and future customers.

GRI's program must provide timely mutual benefits to the ratepayers and the industry. GRI's planning process includes, as a critical element, a method for prioritizing research activities based on their expected benefits. This planning methodology, called project appraisal methodology, or PAM for short, was developed and refined based on techniques used by American industries and the U.S. Department of Defense. The major refinement has been on defining specific categories of ratepayer benefit.

PAM is one of the most sophisticated planning tools used in the U.S. and has been the subject of a number of reviews by prestigious groups including the National Academy of Engineering, the General Accounting Office, the Energy Research Advisory Board of the Department of Energy and the Interagency Project Selection Coordinating Group. All have reached favorable conclusions on PAM and have also made valuable suggestions for continued improvement of the methodology. The GAO study recommended government consideration of PAM as a mechanism for setting priorities for synthetic fuels developments.

Through vigorous application of the PAM process and careful review of its results by advisory groups, GRI funds only that research which has the maximum chance of providing ratepayer benefits. Though GRI is only a few years old, it already has much to show in terms of beneficial results. I have included Attachment RBR-2 which provides numerical data on the benefits of completed research. To explain the attachments, I will describe one project in detail.

GRI completed research in 1981 on a revolutionary new gas furnace design, called the pulse combustion furnace, which is now in full production by Lennox Industries. This furnace burns natural gas in a series of pulses within a closed chamber rather than using a continuously burning flame. This principal allows increased efficiency at reasonable cost and also allows exhaust from the furnace to be vented from a conventional plastic pipe--no chimney is required. For this technology, as well as any other efficient utilization technology, the benefits will accrue principally to the ratepayer who purchases the new equipment. However, some benefits also result for all ratepayers, not just the purchaser. For the pulse furnace, depending on climate, size of home, and degree of home insulation, annual fuel savings will range from $150 to $300 for ratepayers who replace a 65 percent efficient furnace and from $50 to over $100 for those who choose a pulse furnace instead of an 80 percent efficient deluxe gas furnace. The analysis in the exhibits assumes an average home with an average heating load, and uses a purchaser fuel savings of $100 per year. Thus, over the 20-year life of the furnace, the purchaser will receive a return of $2,000, minus the incremental purchase price of $340, for a net benefit of $1,660.

These numbers represent benefits to the purchaser of a new technology. However, significant additional benefits for all gas ratepayers result from the use of the gas saved by new efficient technologies to displace higher marginal cost new gas supplies. Thus, Oklahoma gas ratepayers will benefit even from pulse furnaces sold in other locations. To estimate these benefits, we have assumed that the increment between higher cost new gas supplies and the average gas acquisition cost will remain at today's level of approximately $2.00/mmBtu (1981$). Attachment RBR-2 also shows these benefits as well as the purchaser benefits for the pulse furnace and three other completed research efforts.

Combining these benefits and conservatively estimating unit sales for just the four technologies described in Attachment RBR-2, the benefits for the year 1990 alone will amount to between 1.1 to 1.5 billion dollars (1981$). Cumulative benefits over the life of these products are very significant indeed.

However, to present a complete picture, we must examine some non-economic factors including reliability, maintainability, environment, and safety, and the benefits for projects in areas other than utilization. A brief summary of some of these other ratepayer benefits is included as Attachment RBR-3.

We at GRI also feel that we have had a very positive influence on the marketplace by increasing the level of competition. Of course, increased competition in the gas technology market increases the quality and variety of products offered to the consumer/ratepayer, while having a dampening effect on the prices of those products. For example, we feel that GRI-sponsored research deserves much of the credit for stimulating the recent market introduction of other advanced, high efficiency furnaces. At the time the pulse combustion furnace was first announced in the trade press (Appliance Manufacturer, November 1980) seven major gas heater manufacturers told Appliance Manufacturer that they had no plans to market a condensing furnace. Lennox, which was participating in the GRI research program, announced that it was planning to market such a furnace. Amana and others have subsequently entered the market with their own products to compete directly with Lennox. Successful research in any product area will encourage other manufacturers to introduce competitive products. This results in lower prices to consumers and represents a critical value of ratepayer sponsored research which cannot be easily quantified.

Another benefit for the ratepayer is realized from royalties paid to GRI from commercialization of the pulse combustion furnace by Lennox. GRI invested $760,000 of ratepayers' funds in that project. We estimate that we will receive $2 million in royalties from sales of the furnace by Lennox through 1988, or far more than was invested. All of these funds are applied to the subsequent year's research and development program to reduce the funding requirements. Therefore, the funding unit on each Mcf of gas is reduced accordingly.

I have described some of the present benefits from GRI, but gas customers can also expect benefits in the next few years in the area of gas industry operations. Let me cite some examples:

- Research on plastic pipe quality control has the potential of providing significant economic and safety benefits. This quality control research provides direct financial benefits by reducing the need for replacement of defective pipe. A savings of $30,000 per mile of defective pipe not installed has been estimated. Analyses of plastic pipes that have failed in gas service or while being tested also continue to be added to a library of failures annotated with possible corrective action so that other users may take steps to avoid similar failures in their systems.
- We're developing a rotary excavator for removing soil. It won't rupture metal or plastic pipe or sever electric or television cable. It can reduce the time of digging by 50 percent, meaning quicker service repairs at less cost. We anticipate a possible market entry date of 1984 for the tool; an integrated system is planned for 1986 entry.
- A new soil stablizer that improves compaction and eliminates settling in backfilled area will make it possible to complete a repair with crews going to an excavation site only once. Projected commercial availability is 1984.
- A portable ultrasonic device is being developed to test the integrity of heat-fused, joints in plastic pipe joints in the field. A field test of a more advanced unit will begin this fall with the first commercial device targeted for mid 1985.
- A water jet that uses entrained abrasives to cut through pavement to reduce cutting time by 33 percent will begin a second-generation unit field test this summer. A commercial unit is anticipated in 1985.

GRI is also working hard to provide improved gas service for residential use in the next few years. Our goal is to provide gas equipment options of equivalent or higher quality and at competitive or lower cost than alternate energy sources:

- The heat pipe furnace will be vented directly without the need for a chimney, have a seasonal efficiency goal of 85 percent and is expected to be competitive with gas furnaces in the mid-price range. This will make high efficiency furnaces affordable by more consumers. There is now a 10-unit field test, and based on the results, this unit should be commercially available in 1984. It could be a big winner for the gas consumer. Moreover, it may make room-by-room temperature control possible, thereby further increasing overall efficiency.

- A 92 percent efficient, vented pulse combustion space heater will bring high efficiency technology to room or zone heating, with applications for room additions, zone heating with an existing central furnace, and homes in southern states where central heating may not be required. Our goal is a high-performance system to compete in the $200-400 price range which will put this furnace within the range of many lower income gas customers, who desire higher efficiency gas products. There will be a 20-unit field test during the 1983-84 heating season. Market entry is anticipated in 1984.

- Pulse combustion technology is now being applied to a residential water heater. It will be targeted for a payback within 3 to 4 years or less with an annual efficiency of approximately 85 percent--compared to only 60 percent for conventional water heaters of the same size. It will produce annual energy savings of $100 over the conventional unit. During 1983, there will be a five-unit field test of 40- and 50-gallon models. Commercial entry is planned for late 1984 or early 1985.

- Another project that will help current gas users is a low-cost ceramic burner insert for water heaters and a metal insert for reducing emissions from furnaces. This insert technology should be commercially available in 1984 for both water heaters and furnaces.

- A cost-effective device that integrates a gas furnace, an electric air conditioner and a heat recovery system providing hot water is being developed. The goal is a 55 percent reduction in operating costs targeted for small houses and new multi-family housing. An initial field test begins later this year.

- Another development is an advanced gas range with a flame insert burner for improved cooktop performance. Goals are a 50 percent reduction in nitrogen oxides emissions (NO_x) with no reduction in efficiency. Twenty units will be field tested in late 1983.

GRI is also improving energy service for the commercial sector in the near term.

- One significant development is a commercial-size water heater which has undergone comprehensive field testing. The water heater performance goal is 90 percent energy recovery efficiency with less than a 1 percent standby loss. This is a major improvement on equipment now on the market and translates into a one-year payback period on the cost premium. Market entry is targeted for early 1984.

- For new uses of gas within the commercial sector, a leading candidate is the fuel cell which converts natural gas to electricity and heat by means of this silent, highly efficient electrochemical process. Initial units have already accumulated 5,000 field test hours in three test sites. Forty-five more-advanced units are being manufactured and will begin to be sited this fall. We're targeting for the first commercial offering by 1985. Studies we have conducted show that for an operation such as a 24-hour restaurant the fuel cell could achieve 34 percent annual energy resource savings over the conventional unit it is replacing, amounting to cost savings of $20,000 to $40,000 per year depending upon climate and energy costs.

Our technical goal is an early entry installed cost of $2,000 per kilowatt in 1985, with a system efficiency exceeding 80 percent.

- We also project a major new opportunity for engine-driven cogeneration, particularly in prepackaged systems for light commercial use. Three companies are about to begin a field test in December of a packaged 70 kilowatt engine system with integrated heat recovery and an absorption chiller. The target is an 80 percent efficient system, skid-mounted and easily installed, at a system cost below $1000 per kilowatt. Preliminary estimates show a potential savings of $15,000 to $30,000 per year, with a payback of 2 to 5 years.
- Another new job for gas is desiccant dehumidification which was field tested this summer. Desiccant dehumidification uses gas in a new application--especially during summer months. Our goal is an integrated system with a 20 percent total energy savings--both gas and electricity--at a lower first cost than conventional equipment. Market entry should be 1984.
- An integrated pulse combustion fryer and water heater with a goal of 70 percent improvement in fryer efficiency and heat recovery for water heat in fast food restaurants will be introduced into the market in 1985.
- The development of a roof-top heat pump featuring a high-speed gas turbine in a 10-ton unit is proceeding toward a goal of 30 percent engine efficiency. The system will be scalable to larger commercial sizes. An initial 10-unit field test will begin in 1984, with full commercialization expected in 1988. We estimate that a commercial establishment could save $600 per year over high efficiency gas heat and electric air conditioning in this region.

GRI is seeking to improve industrial processes with advanced gas technologies to protect existing markets and develop new gas uses wherever a cost or performance advantage can be identified:

- In a process improvement for a traditional gas market, we are developing a fiber burner for refinery process heaters. Goals for these large systems are a 10 percent increase in heater productivity, highly uniform radiant heat, and nitrogen oxide emissions of less than 15 parts per million. Commercial availability is projected for 1984. This exciting technology has a variety of potential applications. For example, we're starting a field test on a retrofit burner for an industrial boiler. We also have projects using fiber burners in new commercial space heaters, residential water heaters, and residential boilers.
- A proof-of-concept field test was recently completed for an open-cycle, rotary screw heat pump that upgrades waste steam to process quality steam. The system reduced fuel consumption by 50 percent as compared with a direct-fired boiler. Surveys have identified the market potential for 2800 gas heat pump systems in the petroleum, chemical, paper, and food industries. Full commercialization is imminent.

- An excellent opportunity for new industrial use of gas is a new burner for melting scrap for an electric arc furnace. A single burner field test goes into a mill this month. Commercialization could be in 1984. We expect a 15 percent reduction in melting cycle time, a 40 percent reduction in refractory consumption, and a 12 percent increase in electrode life to provide a strong incentive for mills to adopt this new use for gas.
- An advanced gas-fired furnace system using a high-temperature recuperator and combustor with ceramic fiber insulation is proceeding to commercialization by the end of 1983.
- An aluminum scrap preheater, developed by Midland-Ross Corporation, is designed to preheat light gage aluminum scrap by using flue gases from an adjacent gas-fired melter will reduce fuel consumption by 30 percent and increase melter capacity by 35 percent with improved product quality. It will be field tested this year.

Although adding new gas supplies is not urgent in the near-term, GRI is pursuing the improved recovery of unconventional natural gas in order to hold down the cost:

- A diagnostic technique that will improve gas recovery from dense geological formations is being tested at an Oklahoma field. A 25 percent improvement in fracture effectiveness can reduce gas production costs by up to 20 percent due to the increased gas yield per well. This concept has been tested in two experimental wells at Amoco's Catoosa site near Tulsa. Additional tests on deeper wells are scheduled.
- Another fracturing technique being developed for use in shale by Sandia National Laboratory involves burning high-energy materials to produce a controlled pressure pulse designed specifically for the geologic stratum. This results in improved multiple fractures. Field tests will continue through August, and the technology should become available for commercial use in 1984.
- Through a contract with CER Corporation, GRI has undertaken a study of the Arkoma Basin and Ovachita Mountains to present a geologic reconnaissance of the stratigraphy and structure in regard to low permeability gas bearing formations.

This completes the summary of my prepared testimony. For further detail about these GRI projects and GRI itself, please consult the more detailed direct testimony.

Schedule 1
Results from Completed GRI Efficient Utilization R&D (1981$)

Product	Efficiency Improvement (1)	Annual Fuel Savings in 1990 (2)		Product Cost		Simple Payback, Years (3)
		MMBtu	$	New	Existing	
Pulse Combustion Furnace	13%	15	100	$ 1,250	$ 910	3.4
Deep Fat Fryer	35%	30	185	1,250	835	2.2
Ladle Heater	82%	63,000	345,000	157,000	93,700	0.2
Ceramic Fiber Furnace Insulation	45%	4,200	23,000	35,400	20,400	0.7

Notes

(1) Based on percentage reduction in fuel use - new technology vs. existing technology. For example, an 80% efficient deluxe gas furnace in a typical northern climate uses nearly 115 MMBtu, while a 92% efficient pulse combustion furnace uses approximately 100 MMBtu, or a 13% reduction in fuel use.

(2) Annual Btu savings based on efficiency improvement as above. 1990 dollar savings are in 1981$ based on the following fuel prices takes from the GRI 1982 Baseline Projection:

Average Gas Acquisition Cost	$4.41/MMBtu
Residential Gas Price	$6.58/MMBtu
Commercial Gas Price	$6.20/MMBtu
Industrial Gas Price	$5.46/MMBtu

(3) Time required to repay increase in first cost from annual fuel cost savings.

Schedule 2

Estimated Fuel Cost Savings for All Ratepayers in 1990
From Completed GRI Efficient Utilization R&D
(1981$)

Project	Annual Fuel Savings per Unit in 1990			Units Anticipated in 1990	Total Estimated Annual Ratepayer Fuel Cost Savings in 1990, $ millions
	Purchaser Fuel Cost Savings (1)	Displaced Marginal Supplies (2)	Total		
Pulse Combustion Furnace	$ 100	$ 30	$ 130	2-3 million (3)	260-390
Deep Fat Fryer	185	60	245	100,000	25
Ladle Heater	345,000	125,000	470,000	1,600	750
Ceramic Fiber Furnace Insulation	23,000	8,400	31,400	2,500	80

Notes

(1) Based on the following 1990 gas prices (in 1981$) from the 1982 GRI Baseline Projection:

Average Gas Acquisition Cost	$4.41/MMBtu
Residential Gas Price	$6.58/MMBtu
Commercial Gas Price	$6.20/MMBtu
Industrial Gas Price	$5.46/MMBtu

(2) Avoided Cost by Displacement of High Marginal Cost Supplies $2.00/MMBtu

(3) Does not include an additional 2-3 million high efficiency furnaces which are anticipated to enter the market to compete with pulse combustion furnaces.

Attachment RBR-3

Benefits of Selected GRI Research Projects

Technology	Benefit
Gas Supply Research	
Tight Gas Sands Resource Characterization	Increased supply of lower cost gas resource
Gas Resource Information System (GRIS)	Determine gas production potential from various Devonian shale formations
Coal Gasifier Materials	Reduced design and construction costs for coal gasification facilities
Enhanced Service Research	
Plastic Pipe Quality Control	Reduced leakage, increased safety, reduced pipe maintenance costs
Physical Properties Data for Methane	Improved standards for LNG custody transfer, increased accuracy
Orifice Meter Coefficients	Reduced costs in metering, reduced recompression losses, accurate customer billing
LNG Safety Techniques	Reduced facility construction costs, increased safety
Efficient Utilization Research	
Pulse Combustion Furnace	Reduced air infiltration, elimination of chimney, lower emissions
Commercial Convection Oven	Reduced cooking time, reduced operating costs
Commercial Deep Fat Fryer	Reduced quantity of cooking oil, reduced cleaning requirements
Ladle Heater	Reduced furnace temperature, longer refractory life
Ceramic - Fiber Furnace Insulation	Reduced noise levels
Furnace Heat Exchanger Leak Detection Technique	Increased safety
Low NO_x Burners	Reduced industrial emissions, improved indoor air quality

DON FUQUA (Fla.), Chairman

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WASHINGTON, D.C. 20515
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TOM LEWIS, FLA.

J. H. POORE
Executive Director

ROBERT C. KETCHAM
General Counsel

DAVID S. JEFFERY
Minority Staff Director

June 28, 1983

Mr. Eugene N. Oatman
Manager of Energy Resources Department
Electric Power Research Institute
P.O. Box 10412
Palo Alto, CA 94303

Dear Mr. Oatman:

We want to thank you for your excellent testimony before the Subcommittee on Energy Development and Applications and the Subcommittee on Energy Research and Production on June 22 on the subject of lower oil prices and their implications for energy research and development policy. We would like to supplement the record of the hearing with some additional questions on this topic.

We appreciate your cooperation on this matter. If you have any questions regarding this request, please contact Dr. Harlan Watson of the staff of the Subcommittee on Energy Development and Applications at (202) 225-4320.

Sincerely,

Don Fuqua
DON FUQUA, Chairman
Subcommittee on Energy
Development and Applications

Marilyn Lloyd
MARILYN LLOYD, Chairman
Subcommittee on Energy
Research and Production

DF/ML:Wba
Enclosure

Lower Oil Prices: Implications for Energy R&D Policy
Additional questions for Mr. Oatman

1. What general principles should guide the federal energy R&D program?

2. Do you have any indication of the dollar payback the utility industry is receiving per dollar of EPRI research investment? Is it $0.50, $1, $5, $10, or what?

3. Has the recent world oil price situation affected EPRI R&D programs, and if so, how? What are the implications for the federal energy R&D program?

4. The chart on page 3 of your testimony lists five R&D planning criteria used by EPRI to evaluate specific research projects and areas. Are all these criteria given equal weight or is the minimization of future capital and revenue requirements the most important criterion?

EPRI
Electric Power
Research Institute

July 12, 1983

The Honorable Don Fuqua
Chairman, Subcommittee on
Energy Development and Applications
Committee on Science and Technology
U.S. House of Representatives
Washington, D.C. 20510

The Honorable Marilyn Lloyd
Chairman, Subcommittee on
Energy Research and Production
Committee on Science and Technology
U.S. House of Representatives
Washington, D.C. 20510

Dear Congressman Fuqua
and Congresswoman Lloyd:

I am pleased to respond to the supplemental questions regarding my testimony on the use of price projections, forecasts and modelling to examine the impacts of lower oil prices on EPRI R&D planning before your Subcommittees on June 22.

I will be happy to provide additional information if it would prove helpful.

Sincerely,

Eugene N. Oatman

Eugene N. Oatman
Manager
Energy Resources Program

ENO:ss

Enclosure

3412 Hillview Avenue, Post Office Box 10412, Palo Alto, CA 94303 Telephone (415) 855-2000
Washington Office: 1800 Massachusetts Ave., NW, Suite 700, Washington, DC 20036 (202) 872-9222

SUPPLEMENTAL QUESTIONS FOR EUGENE N. OATMAN

LOWER OIL PRICES: IMPLICATIONS FOR ENERGY R&D POLICY

Q. What general principles should guide the federal energy R&D program?

A. R&D policies, whatever the sponsoring institution, should be framed within a set of long-range strategic objectives. The EPRI R&D program, because it focuses on the fundamental criteria for success of the electric utility industry, remains relevant in the face of changing perceptions about uncertainties such as world oil price. Energy R&D policies, without the tether of key strategic objectives are apt to be blown about by the turbulence from short run fluctuations in major uncertainties. A specific guiding principle for the federal energy R&D program would be to conduct research that promises clear benefits to the public over a period of time beyond the "risk horizon" of the private sector under a wide range of possible future conditions.

Q. Do you have any indications of the dollar payback the utility industry is receiving per dollar of EPRI research investment? Is it $0.50, $1, $5, $10 or what?

A. One approach to assessing potential benefits has been to establish targets in major areas of electric utility operation such as a one percent improvement in availability from baseload plants and then to estimate regional and national savings that would result from achievement of those targets. R&D options can then be compared against the target benefits to establish program priorities. The results of these "one percent" studies appear in a special EPRI report, P-2851-SR on R&D Benefits Assessment - A Regional Approach that I am enclosing for your information.

However, no meaningful industry-wide number in terms of dollar payback per dollar of research investment exists, primarily because of the undue number of assumptions involved. On completed research, "first" users have attested to one-hundred technical applications resulting in benefits of $890 million for their specific systems. Extrapolating those individual savings to the more than 500 EPRI member utilities is extremely difficult. Nevertheless, in each instance where a member company has looked specifically at its benefits from EPRI research, there has been a positive return on its investment.

Q. Has the recent world oil price situation affected EPRI R&D programs, and if so, how? What are the implications for federal energy R&D programs?

A. The recent world oil price situation has affected the emphasis and timing of particular segments of EPRI research to some extent, but not dramatically. The prospect of lower oil prices in the short-to-medium-term reinforces the desirability of research efforts to hold down the price of electricity through efficiency improvements. Technologies that provide cost savings and flexibility in the longer term will attain commercial effectiveness in the 1990's when the price of oil is projected to be increasing once again in real terms.

One of the studies cited in my prepared testimony, the EMF World Oil Study, contains the underlying assumption that, over the next several decades, reserves of low cost oil and gas will be depleted and that the unmistakable long-run trend in oil prices is upward. Because of the lead times required to develop and commercialize substitute technologies, the federal energy program should persevere in longer range R&D in fluid fuels.

Q. The chart on page three of your testimony lists five R&D planning criteria used by EPRI to evaluate specific research projects and areas. Are all these criteria given equal weight or is the minimization of future capital and revenue requirements the most important criterion?

A. Not all the criteria are weighted equally at any point in time. The current program places highest priority on research and development to help minimize utility financial and revenue requirements. Earlier, concerns with meeting environmental requirements dominated and could do so again. The criteria are related, of course, in the sense that cost or capital minimizing R&D strategies should be evaluated in terms of criteria for fuel availability, environmental compliance, productivity and flexibility under uncertain future conditions.

DON FUQUA (Fla.), Chairman

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FREDERICK C. BOUCHER, VA.

U.S. HOUSE OF REPRESENTATIVES
COMMITTEE ON SCIENCE AND TECHNOLOGY
SUITE 2321 RAYBURN HOUSE OFFICE BUILDING
WASHINGTON, D.C. 20515
(202) 225-6371

LARRY WINN, JR., KANS.
MANUEL LUJAN, JR., N. MEX.
ROBERT S. WALKER, PA.
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General Counsel
DAVID S. JEFFERY
Minority Staff Director

June 28, 1983

Dr. Morris A. Adelman
Professor of Economics
Massachusetts Institute of Technology
Cambridge, Massachusetts 02139

Dear Dr. Adelman:

We want to thank you for your excellent testimony before the Subcommittee on Energy Development and Applications and the Subcommittee on Energy Research and Production on June 22 on the subject of lower oil prices and their implications for energy research and development policy. We would like to supplement the record of the hearing with some additional questions on this topic.

We appreciate your cooperation on this matter. If you have any questions regarding this request, please contact Dr. Harlan Watson of the staff of the Subcommittee on Energy Development and Applications at (202) 225-4320.

Sincerely,

Marilyn Lloyd

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Enclosure

Lower Oil Prices: Implications for Energy R&D Policy
Additional Questions for Dr. Adelman

1. What general principles should guide the federal energy R&D program?

2. Do we have in hand a good theory or even a good rule of thumb to explain the relation between oil prices and the discovery and production of oil?

3. What world oil price level would be optimal from OPEC's point of view to protect their long-term market? Is today's current price too high?

4. It has been argued by advocates of an oil import fee that imported oil is underpriced because it neglects a "security" premium. Does this argument have any merit from an economic point of view?

5. In the closing paragraph of your prepared testimony, you suggest that it is incorrect to ask what policy is appropriate in view of lower oil pricas. Rather, you say, we should be asking what poicy is appropriate for an uncertain and dangerous future. What policy or policies would you recommend?

"LOWER OIL PRICES: IMPLICATIONS FOR ENERGY R&D POLICY"
Additional questions for Dr. Adelman

1. What general principles should guide the federal energy R&D program?

A. Programs should be funded which promise energy sources at costs and prices equal to, or lower than, current prices. Anything which costs more is not worth having.

As for the supposed doubling or tripling of price by 2010 A. D., that is an exercise in arithmetic, and no reason for spending public funds, and misusing our scarce supply of trained brainpower..

Although the goals of this program should be technology, not knowledge for its own sake, the focus should not be on particular products or methods, but rather on processes which have been used for thousands of years without being well understood. How does combustion work? What makes hydrogen molecules combine with carbon to make a liquid or gas? How do we break rocks (some 99 percent of the energy applied is wasted)? How much of acid rain proceeds from natural causes, how much from man-made?

R&D which promised profit to the private enterprise doing it should not be directly or indirectly supported. Government support should be reserved for those kinds of R&D which promise profit, but profit which the practitioner cannot appropriate for his own benefit, hence which private enterprise cannot be expected to make.

2. Do we have in hand a good theory or even a good rule of thumb to explain the relation between oil prices and the discovery and production of oil?

A. We have a good theory, but we lack precise numbers to fit into it, hence predictions must be mostly qualitative, or in terms of more or less.

The theory states that under competition, each actual or potential oil producer will respond to a higher price by investing in higher cost facilities and longer shots in exploration. He may do more infill drilling to get oil up faster; exploit or seek smaller or deeper or otherwise more costly pools which previously did not pay to produce. Certainly this is what has happened in the United States and other competitive areas.

Under monopoly, the contrary is true. Producers fix the price, and they protect it by curtailing output. Therefore they curtail investment in exploration and development. Furthermore, the higher the price, the greater the revenues of the monopolists, the better able are they to resist competitive pressures.

In the case of the cartel of the OPEC nations, there is a further depressant. Two major producers have been able to afford a war, which has reduced their production sharply.

Thus if the cartel were weaker and prices and oil revenues dropped, the cartel would invest and produce more, the the war would die for lack of support, and oil production would greatly increase, further weakening prices. I would not count on the cartel becoming sufficiently weaker.

3. What world price level would be optimal from OPEC's point of view to protect their long-term market? Is today's current price too high?

A. This is an important relevant question, but it cannot be precisely answered because OPEC nations are not alike. The price level optimal for a low-cost high-reserve producer is too low for a high-cost low-reserve producer.

I do not believe that anyone can tell whether $34 was "too high", i. e., above the OPEC optimum. The market feedback is too slow and uncertain. But the following can be said:

(a) Three years ago, OPEC (and industry) opinion was that the optimal or ceiling price was just a shade under the cost of synthetic fuels, whatever that might be. It should now be clear that this is wrong: the ceiling is set by consumer reaction, which like a glacial drift is imperceptible in the short run and irresistible in the long run.

(b) Therefore, while there may still be room to raise prices higher--I personally believe there is--that room is limited. We need look only at the second price explosion, and see how much more strong was the reaction in the marketplace. It is a mistake to project percentage increases. What counts is the absolute increase, which is what governs substitution. A customer might do nothing after an increase from $1 to $5, because the reward for conserving was only $4, which would not pay a sufficient return on the needed investment. A further increase from $5 to $10, "only" a doubling as against a quintupling, would raise the payoff to $9, and open a wide range of alternatives.

If we think only of percentages, we can envisage the price rising from $30 to $84 because, after all, "that doesn't even triple it, and it more than tripled in the 1970s." But the interval from $30 to $84 should be compared with the interval from about $4 (in 1983 prices) to $30. We are far from having adjusted to that change. The reaction is still going on. Industrial production is up smartly from a year ago, but industrial use of oil and gas is actually down. Consumer expenditures are also up, but gasoline use is static or possibly declining.

Furthermore, the slowdown in world economic growth, in part caused by the oil shocks, will not lift like a cloud. All in all, the chances are remote of prices going permanently to much higher levels. The only way is by the permanent destruction of Persian Gulf facilities.

4. It has been argued by advocates of an oil import fee that imported oil is underpriced because it neglects a "security" premium. Does this argument have any merit from an economic point of view?

A. The argument is correct. Every barrel of imported oil is "polluted" by being insecure, even when the particular country is altogether reliable. The tariff is simply a pollution charge. It puts the consumer on notice that he is imposing a charge upon the whole economy, which is not covered by the price. Absent a tariff, we are subsidizing oil consumption.

Of course, a tariff would raise the domestic price level, and offer domestic producers an incentive to produce more, up to but not beyond the point where the price equals the foreign price plus tariff. At that point, an incremental domestic barrel costs as much, and is worth as much, as a foreign barrel plus the security charge.

This argument has nothing to do with the budget and the deficit. The tariff would be worth having if it contributed nothing to revenues, and if it came entirely out of the consumers' pocket. In fact, much and perhaps most of it will be borne by the oil exporters. They have always hated tariffs, and excise taxes on consumption, because they pay some of it. Hence Sheik Yamani's threats to boycott any nation levying a tariff. We should not go out of our way to call his bluff, but it would be a useful by-product of imposing a tariff.

5. In the closing paragraph of your prepared testimony, you suggest that it is incorrect to ask what policy is appropriate in view of lower oil prices. Rather, you say, we should be asking what policy is appropriate for an uncertain and dangerous future? What policy or policies would you recommend?

A. First and foremost, resume filling the Strategic Petroleum Reserve, and have in place a plan for using it early on, before spot prices have begun to rise and panic sweeps the market. My suggestion is contained in an article appended to my prepared testimony. There may be better ideas, but just waiting for the crisis to break is wrong.

Second, place a tariff on imported crude oil and products, for the reasons already stated.

Third, there are two issues which look unrelated, but are not. We should decontrol natural gas, and should cease and desist from all official statements about how oil prices are going higher and higher for ever and ever, through the year 2010, etc. Nobody knows any such thing, and nobody should pretend to know.

Because of natural gas price control, the illusion of higher ever higher oil prices forever has damaged the interests of Canada, the U. S., and Mexico. Our neighbors have large natural gas resources which they have neglected to develop.They have felt absolutely certain of a better price later because natural gas price control has served to put exempt gas--deep gas, tight sands gas, etc--far up in price, and our neighbors think that is the "real price", to which they are entitled.

Natural gas decontrol would give one price level, which would be considerably lower than what Canada and Mexico have been hoping for. Individuals in both countries know the truth; unfortunately governments refuse to recognize it, because they will lose face. Decontrolled natural gas, selling at less than what they have recently asked (let alone the $5 which was once thought too low), would drive home the fact that the longer they wait the less they will get. Decontrol would give us cheaper fuel and would give them highly profitable business. The additional fuel would back out OPEC oil from the world market, a blessing in itself.

RESPECTFULLY SUBMITTED.

M. A. Adelman

Hon. Don Fuqua
Hon. Marilyn Lloyd
Committee on Science & Technology
U. S. House of Representatives
Suite 2321 Rayburn House Office Building
Washington, D. C. 20515

APPENDIX II

ADDITIONAL MATERIALS FOR THE RECORD

DOE/EIA-0385 (82)
Dist. Category UC-98

Synopsis of the Annual Energy Review and Outlook--1982

April 1983

Energy Information Administration
National Energy Information Center
U.S. Department of Energy
Washington, D.C. 20585

This report was prepared by the Energy Information Administration, the independent statistical and analytical agency within the Department of Energy. The information contained herein should not be construed as advocating or necessarily reflecting any policy position of the Department of Energy or any other organization.

Administrator's Message

This booklet provides the reader with historical energy information and projections of the Nation's energy future. It is a synopsis of two major reports produced by the Energy Information Administration: the 1982 Annual Energy Review and the 1982 Annual Energy Outlook. (In previous years, those same two reports constituted Volumes Two and Three of the agency's Annual Report to Congress.) Those reports are considered to be centerpieces of the EIA's comprehensive energy data and analysis program. We hope that this booklet, which synopsizes them, provides the reader with important highlights from the reports in a form that is convenient and useful.

J. Erich Evered
Administrator

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43 EXPLANATORY NOTES

45 GLOSSARY

Selected EIA Periodicals (inside back cover)

Remarks

NA	Data not available.
--	Data not applicable.
Rounding	Sum of components may not equal totals due to independent rounding.
Sources	Unless noted otherwise, the source for historical information contained in this booklet is the Energy Information Administration. Sources for particular historical data and projection data series (historical) may vary. See the 1982 Annual Energy Review and 1982 Annual Energy Outlook for detailed source information.
Energy Prices	Historical prices, unless noted otherwise, are in current dollars. See page 42 for historical dollar conversion factors (GNP Implicit Price Deflator).

Released for printing April 26, 1983.

Energy Overview: Major Developments, 1982

During 1982, energy activity in the United States was highlighted by declines in energy production, consumption, and exploration. Significantly, the average wellhead price of crude oil dropped, while that for natural gas rose.

Domestic energy production declined slightly in 1982, as small gains in hydropower and nuclear power production (to record levels for each), and in crude oil production, were more than offset by losses in natural gas production. Crude oil production in the Lower-48 States rose for the first time since 1972. Consumption of energy by electric utilities for generating electricity dropped for the first time since World War II, to below the 1979 level.

For the third straight year, domestic energy consumption declined, reflecting not only high prices and conservation efforts (as in 1980 and 1981) but also a slowdown in economic activity, particularly in the industrial sector. After a 4-year decline, petroleum consumption dropped below 1971's level. Natural gas consumption dropped 1.5 trillion cubic feet, to its lowest level since 1967. After a 3-year increase, coal exports fell slightly. For the third straight year, the

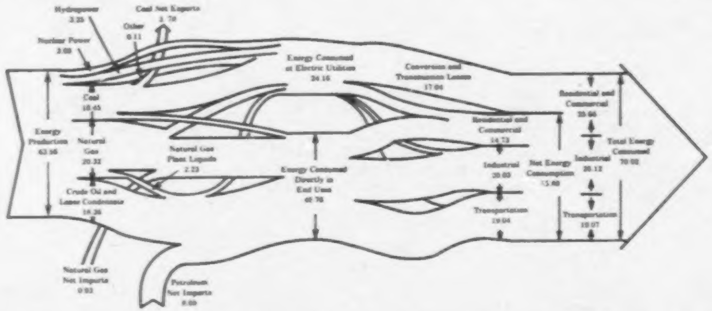
United States was able to significantly reduce its dependence on foreign petroleum sources. Net imports in 1982 equaled 28 percent of consumption, the lowest since the last full year of import controls, in 1972.

Changes in energy prices in 1982 were mixed. Most petroleum prices dropped, but natural gas, coal, and electricity prices increased.

- Crude oil wellhead prices dropped 10 percent, averaging $28.54 per barrel.
- The refiner acquisition cost of imported crude oil dropped 9 percent, to $33.62 per barrel.
- Leaded regular motor gasoline retail prices averaged $1.22 per gallon, down 7 percent from 1981.
- Residential heating oil prices averaged $1.19 per gallon, down 2 percent from 1981.
- Residential electricity prices rose 10 percent, to 6.86 cents per kilowatt-hour.
- The natural gas wellhead price rose 22 percent, to $2.42 per thousand cubic feet.

U.S. Energy Flow Diagram, 1982

(Quadrillion Btu)


Hydropower 3.25
Coal Net Exports 2.78
Other 0.11
Nuclear Power 3.00
Coal 18.65
Energy Production 63.96
Natural Gas 20.32
Natural Gas Plant Liquids 2.23
Crude Oil and Lease Condensate 18.26
Natural Gas Net Imports 0.93
Petroleum Net Imports
Energy Consumed at Electric Utilities 24.16
Energy Consumed Directly in End Uses 46.76
Conversion and Transmission Losses 17.04
Residential and Commercial 14.73
Industrial 20.03
Transportation 19.04
Net Energy Consumption 53.80
Residential and Commercial 25.66
Industrial 26.12
Transportation 19.07
Total Energy Consumed

Note: Total energy consumption with conversion and transmission losses allocated to end-use sectors in proportion to the sectors' use of electricity. Stock changes, miscellaneous supply and disposition, and unaccounted for quantities are not shown.

U.S. Energy Supply
(Quadrillion Btu)

	1960	1965	1970	1973	1975	1978	1979	1980	1981	1982[a]
Production[b]	41.79	49.67	62.51	62.43	60.06	61.23	63.85	64.81	64.43	63.56
Crude Oil & Lease Condensate	14.93	15.52	20.40	19.49	17.73	18.43	18.10	18.25	18.15	18.36
Natural Gas Plant Liquids	1.46	1.88	2.51	2.57	2.37	2.25	2.29	2.25	2.31	2.23
Natural Gas[c]	12.66	15.78	21.67	22.19	19.64	19.49	20.08	19.92	19.69	18.09
Coal[d]	11.12	13.38	15.05	14.37	15.19	15.04	17.65	18.64	18.44	18.45
Nuclear Power	0.01	0.04	0.24	0.91	1.90	3.02	2.71	2.74	2.97	3.08
Hydropower	1.61	2.06	2.63	2.86	3.15	2.94	2.93	2.90	2.74	3.25
Other[e]	(f)	0.01	0.02	0.05	0.07	0.07	0.09	0.11	0.13	0.11
Imports	4.23	5.92	8.39	14.73	14.11	19.26	19.62	15.97	13.94	11.97
Crude Oil[g]	2.20	2.65	2.81	6.89	8.72	13.46	13.83	11.19	9.34	7.35
Refined Petroleum Products[h]	1.80	2.75	4.66	6.58	4.23	4.36	4.11	3.46	3.30	3.27
Natural Gas	0.16	0.47	0.85	1.06	0.98	0.99	1.30	1.01	0.92	0.99
Other[i]	0.07	0.04	0.07	0.21	0.19	0.44	0.39	0.31	0.38	0.37
Adjustments[j]	-0.45	-0.74	-1.41	-0.48	-1.08	-0.36	-1.66	-1.07	-0.07	0.02
Total Supply	45.57	54.85	69.49	76.68	73.09	80.13	81.81	79.72	78.30	75.55

a) Preliminary. At time of release, preliminary coal production was 18.66 quadrillion Btu. b) See Explanatory Note 1, page 43. c) Net dry natural gas. d) Bituminous coal, lignite, and anthracite. e) Geothermal, wood, refuse, and other vegetal fuels used for electricity generation at utilities (see Explanatory Note 2, page 43). f) Less than 0.005 quadrillion Btu. g) Includes imports of crude oil for the Strategic Petroleum Reserve. h) Includes imports of unfinished oils and natural gas plant liquids. i) Includes bituminous coal, lignite, anthracite, coal coke, and hydropower. j) A balancing item. Includes stock changes, losses, gains, miscellaneous blending compounds, unaccounted-for supply, and anthracite shipped overseas to U.S. Armed Forces.

U.S. Energy Disposition
(Quadrillion Btu)

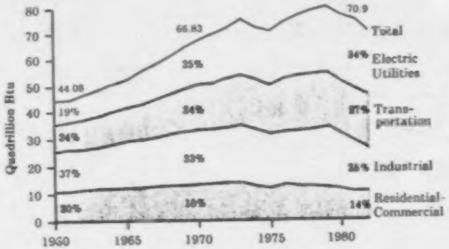
	1960	1965	1970	1973	1975	1978	1979	1980	1981	1982[a]
Consumption	44.08	52.99	66.83	74.61	70.71	78.18	78.91	75.99	73.98	70.92
Refined Petroleum Products[b]	19.92	23.25	29.52	34.84	32.73	37.97	37.12	34.20	31.93	30.33
Natural Gas	12.39	15.77	21.79	22.51	19.95	20.00	20.67	20.39	19.93	18.43
Coal[c]	10.12	11.89	12.66	13.30	12.82	13.85	15.11	15.46	15.97	15.42
Nuclear Power	0.01	0.04	0.24	0.91	1.90	3.02	2.71	2.74	2.97	3.08
Hydropower[d]	1.66	2.06	2.65	3.01	3.22	3.14	3.14	3.12	3.07	3.57
Other[e]	(f)	0.01	0.02	0.05	0.07	0.07	0.09	0.11	0.13	0.11
Net Imports of Coal Coke	-0.01	-0.02	-0.06	-0.01	0.01	0.13	0.07	-0.04	-0.02	-0.02
Exports	1.48	1.86	2.66	2.07	2.39	1.95	2.90	3.73	4.32	4.63
Coal[c]	1.02	1.38	1.94	1.45	1.79	1.10	1.78	2.42	2.94	2.78
Other[g]	0.46	0.48	0.73	0.63	0.60	0.85	1.12	1.31	1.37	1.84
Total Disposition	45.57	54.85	69.49	76.68	73.09	80.13	81.81	79.72	78.30	75.55

a) Preliminary. b) Refined petroleum products supplied includes natural gas plant liquids and crude oil burned as fuel. c) Bituminous coal, lignite, and anthracite. d) Includes industrial generation of hydropower and net electricity imports. e) Geothermal, wood, refuse, and other vegetal fuels used for electricity generation at utilities (see Explanatory Note 2, page 43). f) Less than 0.005 quadrillion Btu. g) Includes crude oil, refined petroleum products, natural gas, coal coke, and hydropower.

Note: Data do not include consumption of wood derived fuel (other than that consumed by the electric utility industry) which amounted to an estimated 2.2 quadrillion Btu in 1981.

U.S. Energy Consumption by End-Use Sector[a]

(Quadrillion Btu)



a) See Explanatory Note 2, page 43.

Note: End-use sector (except electric utilities) energy consumption excluding electricity conversion and transmission losses and electricity sales.

Approximate U.S. Daily per Capita Energy Consumption, 1982

	Quantity
Dry Natural Gas (including consumption at electric utility powerplants).	212 cubic feet
Dry Natural Gas (excluding consumption at electric utility powerplants).	174 cubic feet
Coal (including consumption at electric utility powerplants)	17 pounds
Coal (excluding consumption at electric utility powerplants)	2.6 pounds
Hydroelectricity	4.1 kilowatt-hours
Nuclear Electricity.	3.3 kilowatt-hours
Electricity (including hydro and nuclear power).	25 kilowatt-hours
Refined Petroleum Products (including consumption at electric utility powerplants)	2.8 gallons
Refined Petroleum Products (excluding consumption at electric utility powerplants)	2.6 gallons
Motor Gasoline.	1.2 gallons

Value of U.S. Net Trade[a] in Fossil Fuels

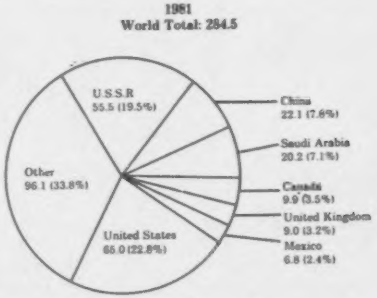
(Billion Current Dollars)

Year	Coal	Coal Coke	Natural Gas	Crude Oil	Refined Petroleum Products	Total
1960	0.35	0.01	-0.02	-0.89	-0.26	-0.82
1965	0.48	0.01	-0.10	-1.11	-0.43	-1.15
1970	0.96	0.08	-0.23	-1.24	-1.00	-1.43
1973	1.01	-0.01	-0.32	-4.24	-2.87	-6.42
1975	3.24	-0.08	-1.06	-18.29	-5.77	-21.96
1978	1.97	-0.36	-1.95	-31.91	-6.13	-38.37
1979	3.34	-0.26	-3.00	-45.66	-8.90	-54.48
1980	4.60	0.07	-3.98	-61.15	-10.58	-71.05
1981	5.89	0.03	-4.06	-60.88	-12.21	-71.23
1982[b]	6.01	0.05	-4.52	-45.25	- 7.79	-51.50

a) Net trade = exports minus imports. b) Preliminary.

International Primary Energy Production,[a] 1981

(Quadrillion Btu)



a) See Explanatory Note 1, page 43.

Value of U.S. Fossil Fuel Production

(Billion Current Dollars)

Year	Crude Oil[a]	Natural Gas[b]	Bituminous Coal and Lignite	Anthracite	Total
1960	7.42	1.79	1.95	0.15	11.31
1965	8.15	2.57	2.27	0.13	13.12
1970	11.19	3.73	3.77	0.11	18.80
1973	13.07	4.98	5.05	0.09	23.19
1975	23.45	9.05	12.47	0.20	45.17
1978	28.60	18.18	14.49	0.18	61.45
1979	39.45	24.16	18.36	0.20	82.17
1980	67.93	32.40	20.20	0.26	120.79
1981	99.40	39.95	21.51	0.24	161.10
1982[c]	90.33	44.58	22.38	0.20	157.49

a) Includes lease condensate. b) Marketed production. c) Preliminary.

Prices of Domestically Produced Fossil Fuels

(Current Cents per Million Btu)

Year	Crude Oil[a]	Natural Gas[b]	Bituminous Coal and Lignite	Anthracite	Composite[c]
1960	49.7	12.6	18.3	33.0	28.1
1965	49.3	14.5	17.5	35.3	27.6
1970	54.8	15.4	25.5	47.1	31.5
1973	67.1	20.1	35.5	58.9	39.6
1975	132.2	41.1	82.9	137.9	82.2
1978	155.2	83.6	97.1	149.9	111.3
1979	217.9	108.1	104.7	174.1	141.4
1980	372.2	146.1	109.2	182.1	204.5
1981	547.8	181.5	117.5	186.9	274.9
1982[d]	492.1	221.8	122.0	198.4	276.7

a) Includes lease condensate. b) Wet natural gas, prior to extraction of natural gas plant liquids. c) Derived by multiplying the price per Btu of each fossil fuel by the total Btu content of the production of each fossil fuel and dividing the accumulated price of total fossil fuel production by the accumulated Btu content of total fossil fuel production. d) Estimated.

Note: All fuel prices taken as close as possible to point of production.

Energy Resources and Producing Indicators

In 1980, the mean estimate of domestic undiscovered recoverable oil resources[1] by the U.S. Geological Survey totaled 83 billion barrels, of which 34 percent was estimated to be offshore. Alaska (including offshore areas) is estimated to contain 23 percent of the undiscovered recoverable resources and the Gulf of Mexico area (including the onshore Western Gulf area) 16 percent. The mean estimate of domestic undiscovered recoverable natural gas resources[1] totaled 594 trillion cubic feet--427 trillion cubic feet onshore, 167 trillion cubic feet offshore. The Gulf Coast, the Colorado Plateau, and the Basin and Range contain significant portions of the onshore amount. The Gulf of Mexico and Alaska contain major portions of the offshore total.

The Demonstrated Reserve Base[1] (DRB) of coal in the the United States, an estimated 473 billion tons as of January 1, 1980, is widely distributed geographically, with 45 percent occurring in States east of the Mississippi River and 55 percent occurring in western States and Alaska. Uranium resources[2] with "forward" costs of $50 or less per pound, as of January 1, 1982, were estimated to be 2.6 million short tons. Uranium production in 1981, primarily from mines located in the West and Southwest, totaled 13,500 short tons of uranium oxide (U_3O_8), a 30-percent decrease from 1981.

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[1] See Explanatory Note 3, p. 43. [2] See Glossary, p. 46.

Domestic Oil and Gas Producing Indicators

Year	Producing Oil Wells[a]		Producing Gas Wells[a] (thousands)	Operating Refineries[b]	
	Number (thousands)	Production per Well (barrels per day)		Number	Capacity (million barrels per day)
1960	591	12.0	91	290	9.84
1965	589	13.3	112	273	10.16
1970	531	18.0	117	262	11.88
1973	497	18.3	124	253	13.45
1975	500	16.8	132	262	14.70
1978	517	17.0	157	290	16.79
1979	531	16.3	170	301	17.15
1980	548	15.9	182	311	17.56
1981	557	15.4	199	315	18.05
1982	[c]569	[c]15.1	[c]216	254	16.10

a) As of December 31. b) Operating and operable shutdown refineries in the United States, excluding the Hawaiian Foreign Trade Zone, as of each January 1. An additional 1.8 million barrels per day of capacity was operable but idle on January 1, 1982. c) Estimated.

Domestic Oil and Gas Drilling Activity

Year	Average Number of Rotary Rigs in Use[b]	Wells Drilled[c] (thousands)	Successful Wells[c] (percent)	Average Depth[c] (feet)	Average Cost per Well[ac] (thousand current dollars)
1960	1,748	45.62	60.1	4,213	54.9
1965	1,388	38.77	58.2	4,510	60.6
1970	1,028	28.12	60.0	4,953	94.9
1973	1,194	26.59	61.2	5,129	117.2
1975	1,660	37.24	64.4	4,685	177.3
1978	2,259	47.06	65.5	4,826	280.0
1979	2,177	49.82	68.4	4,791	331.4
1980	2,909	60.84	70.3	4,675	367.7
1981	3,970	78.54	70.7	4,602	453.7
1982	3,105	[d]85.86	[d]69.1	[d]4,617	[e]460.0

a) Average cost is the arithmetic mean and includes all costs for drilling and equipping wells and for surface producing facilities. The information reported for 1960 and 1965 is not strictly comparable with the more recent surveys. b) Data are not for the exact calendar year but for the 52 or 53 consecutive whole weeks that most nearly coincide with the calendar year. c) Includes exploratory and development wells; excludes service wells, stratigraphic tests, and core tests. d) Preliminary. e) Estimated.

Sources: Well Costs--American Petroleum Institute, Independent Petroleum Association of America, Mid-Continent Oil and Gas Association. Rotary Rigs in Use--Hughes Tool Company. Others--American Petroleum Institute.

U.S. Uranium Resources,[a] January 1, 1982

(Thousand Short Tons, U_3O_8)

	Forward Cost (dollars per pound)[b]		
	$30 or Less	$50 or Less	$100 or less
Reserves[c]	205	594	894
Potential Resources	1,059	1,974	3,209
Probable	596	1,080	1,740
Possible	227	473	784
Speculative	236	421	685
Total	1,264	2,568	4,103

a) See Glossary, page 46. b) Forward costs are those costs yet to be expended, and do not represent prices at which U_3O_8 will be sold. c) Does not include 140,000 tons of U_3O_8 estimated to be available as a by-product of phosphate and copper production during the 1980-2010 period.
Source: Grand Junction Office (DOE).

U.S. Uranium Production, Exports, and Imports

(Thousand Short Tons, U_3O_8)

	Domestic Production	Exports	Imports[a]
1960	17.64	0	18.01
1965	10.44	0	4.00
1970	12.90	2.10	0
1973	13.24	0.60	0
1975	11.60	0.50	0.70
1978	18.49	3.40	2.60
1979	18.73	3.10	1.50
1980	21.85	2.90	1.80
1981	19.24	2.20	3.30
1982[b]	13.50	1.90	3.80

a) Import quantities through 1970 are reported for fiscal years. Until 1971, the Atomic Energy Commission was the sole purchaser of all imported U_3O_8. b) Estimated.
Source: Grand Junction Office (DOE).

Status of U.S. Nuclear Powerplants, December 31, 1982

	Boiling Water Reactors	Pressurized Water Reactors	Other[b]	Total Reactors	Total Capacity[a] (thousand net kilowatts)
In Operation or Startup[c]	27	50	2	79	63,710
(In Full Operation)	(26)	(49)	(2)	(77)	(61,373)
Construction Permits Granted	19	41	0	60	66,388
(Construction Started)	(19)	(41)	(0)	(60)	(66,388)
Construction Permits Pending	2	0	1	3	2,904
Units On Order	0	2	0	2	2,240
Total	48	93	3	144	135,242

a) The total installed capacity of the units' electrical generator(s) less capacity required for plant operation. b) Includes one graphite-moderated and one gas-cooled (HGTR) reactor in full operation and one fast-breeder reactor with a pending construction permit. c) Excludes three units that have been inoperative for at least 3 years: Humboldt Bay, Dresden-1, and Three Mile Island-2.

U.S. Production of Solar Collectors

	Low-Temperature Collectors[a]		Medium-Temperature, Special and Other Collectors[b]	
Year	Number of Manufacturers	Quantity Manufactured (million square feet)	Number of Manufacturers	Quantity Manufactured (million square feet)
1974	6	1.14	39	0.14
1975	13	3.03	118	0.72
1976	19	3.88	203	1.92
1977	52	4.74	297	5.57
1978	81	5.87	180	4.99
1979	74	8.39	250	5.86
1980	73	12.23	245	7.16
1981	75	8.56	267	11.39

a) Low-temperature collectors are almost exclusively for swimming pool heating. b) Medium-temperature collectors are used primarily for space heating and domestic water heating. Special collectors include evacuated-tube collectors and concentrating collectors; uses include domestic water heating, space heating, and space cooling.

Note: Manufacturers producing more than one type of collector are accounted for in the respective listing.

Wood Burned in Households,[a] December 1980-November 1981

	Households That Burn Wood[b]		Cords Burned		Average Amount Burned per Household	Average Purchase Price[c] (dollars
Household Characteristic	(million)	(percent)	(million)	(percent)	(cords)	per cord)
Census Region						
Northeast	3.5	22.3	13.4	31.3	3.9	69
North Central	3.9	25.0	12.5	29.2	3.2	73
South	4.8	31.0	10.5	24.5	2.2	77
West	3.4	21.6	6.4	15.0	1.9	97
Urban	6.4	40.8	10.2	23.7	1.6	79
Rural	9.2	59.2	32.8	76.3	3.5	74
Total Households	15.6	100.0	43.0	100.0	2.8	77
Amount Burned (cords)						
0.33 to 1.49	7.1	45.7	5.3	12.3	0.7	90
1.50 to 2.49	3.1	19.6	5.8	13.6	1.9	84
2.50 to 3.49	1.8	11.4	5.3	12.3	3.0	58
3.50 to 4.49	1.0	6.4	3.9	9.2	3.9	47
4.50 or more	2.6	16.8	22.6	52.7	8.6	65
Year House Built						
Before 1940	4.0	25.7	16.7	39.0	4.2	56
1940-1959	3.4	22.3	7.6	17.6	4.7	83
1960-1978	7.2	47.0	16.9	39.5	9.3	81
After 1978	0.8	5.1	1.7	4.0	2.1	120

a) See Glossary, page 45. b) Survey is limited to households that burned one-third of a cord or more during the survey period. c) Final purchase during survey period.

Household[a] Heating Fuel-Use, November 1981 (Million Households)

Household Characteristics	Census Region: Northeast	Census Region: North Central	Census Region: South	Census Region: West	Area Type: Urban[b]	Area Type: Rural[b]	Total
Total Households	17.9	21.2	27.7	16.3	57.3	25.9	83.1
Main Heating Equipment							
Central Warm-Air Furnace (Excluding Heat Pump) .	5.2	14.4	12.8	8.0	28.9	11.5	40.4
Steam or Hot Water . . .	9.7	3.1	1.3	0.6	12.4	2.2	14.6
Heat Pump.	0.2	(c)	2.0	0.5	1.8	0.9	2.8
Floor, Wall, or Pipeless Furnace . . .	0.1	0.8	2.3	3.3	5.2	1.3	6.5
Oil or Gas Room Heater .	0.4	1.0	4.6	0.6	3.8	2.8	6.6
Built-in Electric Units	1.1	1.0	1.7	1.7	3.4	2.1	5.5
Wood or Coal Stove . . .	1.1	0.9	2.2	0.7	0.8	4.1	4.9
Other or None	0.1	(c)	0.9	0.8	1.0	0.8	1.8
Main Space Heating Fuel							
Natural Gas	7.0	15.4	13.0	10.8	38.3	8.0	46.2
Electricity	1.5	1.6	7.7	3.4	8.8	5.4	14.2
Distillate Fuel Oil or Kerosene	7.9	1.7	2.2	0.4	8.0	4.2	12.2
Wood	1.1	1.2	2.2	0.8	0.9	4.5	5.4
Liquefied Gases	0.1	1.0	2.1	0.4	0.6	3.1	3.7
Other or None	0.2	0.3	0.5	0.4	0.7	0.8	1.5

a) See Glossary, page 45. b) See Glossary, page 46. c) Indicates zero, not available, or not applicable.

Petroleum

U.S. crude oil (including lease condensate, the liquid condensed from natural gas at or near the surface of gas wells during production operations) is produced primarily in Alaska, Texas, Louisiana, California, and their associated offshore areas. Crude oil production in 1982 averaged 8.7 million barrels per day, slightly higher than the 1979-1981 levels. Petroleum products consumption declined to 15.3 million barrels per day, the lowest level since 1971. The most significant drop was in the consumption of residual fuel oil, which is used primarily to produce steam for industry and at electric powerplants. The decline in petroleum use resulted in a 22-percent decline in total petroleum net imports. 1982 year-end crude oil stocks rose 8 percent, due to additions to the U.S. Strategic Petroleum Reserve (SPR). The 294-million-barrel level of SPR stocks was equal to 91 days of net crude oil imports, up from 55 days in 1981.

Primary Stocks of Petroleum, Year-End

(Million Barrels)

Year	Crude Oil[a]: Strategic Petroleum Reserve[b]	Crude Oil[a]: Other	Refined Petroleum Products	Total
1960	--	240	545	785
1965	--	220	616	836
1970	--	276	741	1,018
1973	--	242	766	1,008
1975	--	271	862	1,133
1978	67	309	901	1,278
1979	91	339	911	1,341
1980	108	358	926	1,392
1981	230	364	890	1,484
1982[c]	294	348	787	1,429

a) Includes lease condensate. b) Does not include imported quantities in transit to Strategic Petroleum Reserve terminals, pipeline fill, and above-ground storage. c) Preliminary.

U.S. Crude Oil Production[a]

(Thousand Barrels per Day)

Year	Lower-48	Alaska	Total	Offshore	Onshore
1960	7,034	2	7,035	319	6,716
1965	7,774	30	7,804	665	7,140
1970	9,408	229	9,637	1,577	8,060
1973	9,010	198	9,208	1,616	7,592
1975	8,183	191	8,375	1,362	7,012
1978	7,478	1,229	8,707	1,136	7,571
1979	7,151	1,401	8,552	1,067	7,485
1980	6,980	1,617	8,597	1,034	7,562
1981	6,962	1,609	8,572	1,034	7,537
1982[b]	6,976	1,695	8,671	1,101	7,570

a) Includes lease condensate. b) Preliminary.

U.S. Refined Petroleum Products Supplied to End-Use Sectors[a]

(Million Barrels per Day)

Year	Residential and Commercial	Industrial	Trans-portation	Electric Utilities[b]	Total
1960	1.71	2.72	5.13	0.23	9.80
1965	1.91	3.26	6.03	0.32	11.51
1970	2.18	3.83	7.76	0.93	14.70
1973	2.23	4.50	9.03	1.54	17.31
1975	1.95	4.06	8.93	1.39	16.32
1978	2.07	4.90	10.13	1.75	18.85
1979	1.73	5.35	9.99	1.44	18.51
1980	1.52	4.85	9.54	1.15	17.06
1981	1.33	4.29	9.47	0.96	16.06
1982[c]	1.27	4.00	9.30	0.69	15.25

a) See Explanatory Note 4, page 44. b) Deliveries to electric utilities; do not equate to consumption by electric utilities. c) Estimated.

U.S. Refined Petroleum Products Supplied[a] by Type

(Million Barrels per Day)

Year	Motor Gasoline	Jet Fuel	Distillate Fuel Oil	Residual Fuel Oil	Ethane and Liquefied Gases	Other Products[b]	Total Products
1960	[c]4.13	0.28	1.87	1.53	0.62	1.36	9.80
1965	4.59	0.60	2.13	1.61	0.84	1.74	11.51
1970	5.78	0.97	2.54	2.20	1.22	1.98	14.70
1973	6.67	1.06	3.09	2.82	1.45	2.21	17.31
1975	6.67	1.00	2.85	2.46	1.33	2.00	16.32
1978	7.41	1.06	3.43	3.02	1.41	2.51	18.85
1979	7.03	1.08	3.31	2.83	1.59	2.67	18.51
1980	6.58	1.07	2.87	2.51	1.47	2.57	17.06
1981	6.59	1.01	2.83	2.09	1.47	2.08	16.06
1982[d]	6.54	1.01	2.68	1.69	1.54	1.80	15.25

a) See Explanatory Notes 4 and 9 (page 44). b) Includes kerosene, petrochemical feedstocks, lubricants, wax, petroleum coke, asphalt, road oil, still gas, natural gasoline, unfractionated stream, plant condensate, and miscellaneous products. In 1960, kerosene-type jet fuel is included; from 1965 on, aviation gasoline and special naphthas are included. In 1981 and 1982, other products include negative barrels per day of distillate and residual fuel oil reclassified as unfinished oils and other products (from both primary and secondary supply) reclassified as gasoline blending components. c) In 1960 only, motor gasoline data were for motor gasoline, aviation gasoline, and special naphtha. d) Preliminary.

U.S. Crude Oil Prices

(Current Dollars per Barrel)

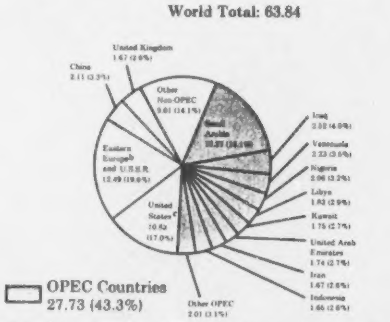
Year	Wellhead Price[b]	Refiner Acquisition Cost[a]		
		Domestic	Imported	Composite
1960	2.88	NA	NA	NA
1965	2.86	NA	NA	NA
1970	3.18	3.46	2.96	3.40
1973	3.89	4.17	4.08	4.15
1975	7.67	8.39	13.93	10.38
1978	9.00	10.61	14.57	12.46
1979	12.64	14.27	21.67	17.72
1980	21.59	24.23	33.89	28.07
1981	31.77	34.33	37.05	35.24
1982[c]	28.54	31.26	33.62	31.93

a) Refiner acquisition cost of crude oil for each category is derived by dividing the sum of the total purchasing (acquisition) costs of all refiners by the total volume of all refiners' purchases. Data for 1970 and 1973 are estimated. b) Domestic average (includes Alaska North Slope crude oil). Price is derived by dividing the sum of the value of all first purchases by the total volume of all first purchasers' purchases. c) Data are for January through November.

Sources: wellhead price--Economic Regulatory Administration; refiner acquisition cost--Energy Information Administration.

International Crude Oil Production,[a] 1980

(Million Barrels per Day)



a) Includes lease condensate and natural gas plant liquids. b) Albania, Bulgaria, Czechoslovakia, East Germany, Hungary, Poland, and Romania. c) Includes refinery processing gain.

U.S. Motor Gasoline and Residential Heating Oil Prices

(Current Cents Per Gallon)

Year	Motor Gasoline[a]		Residential Heating Oil[b]	
	Wholesale[c] (excluding taxes)	Retail[d] (including taxes)	Wholesale[c] (excluding taxes)	Retail[e] (including taxes)
1960	NA	31.1	NA	15.0
1965	NA	31.2	NA	16.0
1970	NA	35.7	NA	18.5
1973	NA	38.8	NA	22.8
1975	NA	56.7	NA	37.7
1978	40.5	62.6	37.1	49.4
1979	62.4	85.7	57.3	65.6
1980	91.0	119.1	80.8	97.8
1981	101.8	131.1	98.2	120.5
1982[f]	93.6	122.2	92.2	118.5

a) Leaded regular. b) No. 2 fuel oil. c) Derived by dividing the sum of the value of all sales to wholesalers by the sum of the total volume of all reported sales to wholesalers. d) Average motor gasoline prices are calculated from a sample of service stations providing all types of service (i.e., full-, mini-, and self-serve) in 85 urban areas. e) Average residential heating oil prices, including taxes, are derived by dividing the sum of the estimated national value of retail sales by the estimated volume of retail sales for residential heating only. January 1975 through October 1980 data are based on a monthly survey of 1,150 firms. November 1980 and forward data are based on a monthly survey of approximately 1,800 firms. f) Preliminary.

Sources: Retail gasoline prices--1960-1973, Platts Oil Price Handbook and Oilmanac, 1974; 1975-1982, Bureau of Labor Statistics (BLS), Consumer Prices: Energy. Retail heating oil--1960-1974, BLS, Retail Prices and Indexes of Fuels and Utilities for Residential Usage. Others--Energy Information Administration.

Natural Gas

At the end of 1982 there were an estimated 216,000 producing gas wells in the United States. Although most natural gas is produced from these natural gas wells, about 20 percent is produced from crude oil wells. U.S. natural gas gross withdrawals in 1982 totaled 20.0 trillion cubic feet, the lowest level since 1966. In 1982, approximately 70 percent of these gross withdrawals were processed to extract liquid hydrocarbons. The processed gas (and gas that does not require processing) is usually between 90 and 95 percent methane, and is referred to as "dry natural gas." It is that gas which is consumed by residences, industries, and electric utilities.

World dry natural gas production in 1980 totaled 53.5 trillion cubic feet. The largest producers were, in order, the United States, the U.S.S.R., the Netherlands, and Canada, accounting for 75 percent of the total. The U.S.S.R., the Netherlands, and Norway were the world's leading exporters of natural gas, while West Germany, the United States, Japan, and France were the leading importers.

U.S. Underground Storage of Natural Gas, Year-End

(Billion Cubic Feet)

Year	Base Gas[a]	Working Gas	Total Gas In Storage[a]
1960	NA	NA	2,184
1965	1,848	1,242	3,090
1970	2,326	1,678	4,004
1973	2,864	2,034	4,898
1975	3,162	2,212	5,374
1978	3,473	2,547	6,020
1979	3,553	2,753	6,306
1980	3,642	2,655	6,297
1981	3,752	2,815	6,568
1982	3,805	3,072	6,877

a) Includes native gas (see Glossary, page 47).

Note: Beginning with 1965 data, all volumes are shown on a pressure base of 14.73 p.s.i.a. at 60 degrees Fahrenheit. For prior years, the pressure base is 14.65 p.s.i.a. at 60 degrees Fahrenheit.

U.S. Natural Gas Gross Withdrawals and Marketed Production

(Trillion Cubic Feet)

Year	Gross Withdrawals: From Gas Wells	Gross Withdrawals: From Oil Wells	Gross Withdrawals: Total	Reservoir Repressuring	Vented and Flared	Marketed Production[a]
1960	10.85	4.23	15.09	1.75	0.56	12.77
1965	13.52	4.44	17.96	1.60	0.32	16.04
1970	18.59	5.19	23.79	1.38	0.49	21.92
1973	19.37	4.70	24.07	1.17	0.25	22.65
1975	17.38	3.72	21.10	0.86	0.13	20.11
1978	17.39	3.91	21.31	1.18	0.15	19.97
1979	18.03	3.85	21.88	1.25	0.17	20.47
1980	17.57	4.30	21.87	1.37	0.13	20.38
1981	17.34	4.25	21.59	1.31	0.10	20.18
1982	15.76	4.20	19.96	1.35	0.08	18.53

a) Includes nonhydrocarbon gases subsequently removed as follows, in trillion cubic feet: 1980=0.19; 1981=0.22; 1982 estimate=0.20. Data are not available on nonhydrocarbon gases removed prior to 1980.

Note: Beginning with 1965 data, all volumes are shown on a pressure base of 14.73 p.s.i.a. at 60 degrees F. For prior years, the pressure base is 14.65 p.s.i.a. at 60 degrees F.

U.S. Consumption of Natural Gas by End-Use Sector[a]

(Trillion Cubic Feet)

Year	Residential	Commercial[b]	Industrial	Electric Utilities	Transportation[c]	Total
1960	3.10	1.02	5.77	1.72	0.35	11.97
1965	3.90	1.44	7.11	2.32	0.50	15.28
1970	4.84	2.40	9.25	3.93	0.72	21.14
1973	4.88	2.60	10.18	3.66	0.73	22.05
1975	4.92	2.51	8.36	3.16	0.58	19.54
1978	4.90	2.60	8.40	3.19	0.53	19.63
1979	4.97	2.79	8.40	3.49	0.60	20.24
1980	4.75	2.61	8.20	3.68	0.63	19.88
1981	4.55	2.52	8.06	3.64	0.64	19.40
1982[d]	4.70	2.61	6.81	3.23	0.59	17.94

a) See Explanatory Note 5, page 44. b) Includes deliveries to municipalities and public authorities for institutional heating and other purposes. c) Pipeline fuel. d) Estimated, except electric utilities.

Note: Beginning with 1965, all volumes are shown on a pressuge base of 14.73 p.s.i.a. at 60 degrees F. For prior years, the pressure base is 14.65 p.s.i.a. at 60 degrees F.

U.S. Natural Gas Prices

(Current Dollars per Thousand Cubic Feet)

Year	Wellhead Price[b]	End-Use Sector Prices[a] Residential	Commercial[c]	Industrial[d]	Electric Utilities	Transportation[e]	Composite
1960	0.14	NA	NA	NA	NA	NA	NA
1965	0.16	NA	NA	NA	NA	NA	NA
1970	0.17	1.09	0.77	0.34	0.29	0.21	0.55
1973	0.22	1.29	0.94	0.46	0.38	0.25	0.68
1975	0.45	1.71	1.35	0.88	0.77	0.40	1.12
1978	0.91	2.56	2.23	1.52	1.48	0.90	1.85
1979	1.18	2.98	2.73	1.82	1.81	1.32	2.21
1980	1.59	3.68	3.39	2.42	2.27	1.85	2.80
1981	1.98	4.29	4.00	3.00	2.89	2.39	3.39
1982	[f]2.42	NA	NA	NA	NA	NA	NA

a) The average for each end-use sector is calculated by dividing the total value of the gas consumed by each sector by the total quantity consumed. See Explanatory Note 5, page 44. b) The U.S. average wellhead price of natural gas is calculated by dividing the sum of total values of natural gas produced in all States by the sum of total quantities of natural gas produced in all States. c) Includes deliveries to municipalities and public authorities for institutional heating and other purposes. d) Includes natural gas lease and plant fuel. e) Pipeline fuel. f) Estimated based on data through October.

Coal

In 1982, coal production totaled 824 million short tons. Commercial quantities of coal are produced in 26 States in the Appalachian, Midwestern, and the Western Plains regions. There are some 5,800 active mines, 15 percent of which provide 80 percent of total output. During recent years, the trend has been to develop larger mines and to consolidate operations for greater efficiency.

Domestic coal consumption decreased in 1982 to 707 million short tons, 3.4 percent below 1981 levels. The leading consumers were electric utilities, even though their consumption of coal fell for the first time since 1958. U.S. coal resources are estimated at more than 1,700 billion short tons at depths less than 3,000 feet; additional coal resources of an additional 2,200 billion short tons are estimated to exist at depths down to 6,000 feet. (Also see "Demonstrated Reserve Base of Coal," page 9.)

U.S. Coal Production[a]

(Million Short Tons)

Year	Method of Mining Underground	Surface	Total	Location West of the Mississippi	East of the Mississippi
1960	292.6	141.7	434.3	21.3	413.0
1965	338.0	189.0	527.0	27.4	499.5
1970	340.5	272.1	612.7	44.9	567.8
1973	300.1	298.5	598.6	76.4	522.1
1975	293.5	361.2	654.6	110.9	543.7
1978	242.8	427.4	670.2	183.0	487.2
1979	320.9	460.2	781.1	221.4	559.7
1980	337.5	492.2	829.7	251.0	578.7
1981	316.5	507.3	823.8	269.9	553.9
1982[b]	312.1	511.9	824.0	264.1	559.9

a) Includes bituminous coal, lignite, and anthracite. Anthracite accounted for approximately 4 million short tons of total coal production in 1982, down from 19 million short tons in 1960. b) Preliminary. At time of release, preliminary coal production was 833.4 million short tons.

Sources: 1960-1970--Bureau of Mines, Minerals Yearbook. Others--Energy Information Administration.

U.S. Coal Disposition[a]

(Million Short Tons)

Year	Consumption by Sector: Electric Utilities	Industrial[b]	Transportation	Residential and Commercial	Total	Exports[c]
1960	176.7	177.4	3.0	40.9	398.1	38.0
1965	244.8	200.8	0.7	25.7	472.0	52.2
1970	320.2	186.6	0.3	16.1	523.2	72.4
1973	389.2	162.1	0.1	11.1	562.6	54.0
1975	406.0	147.2	(d)	9.4	562.6	66.8
1978	481.2	134.5	(d)	9.5	625.2	41.0
1979	527.1	145.1	(d)	8.4	680.5	66.4
1980	569.3	127.0	(d)	6.5	702.7	92.1
1981	596.8	128.4	(d)	7.4	732.6	112.9
1982[e]	594.1	106.2	(d)	7.1	707.4	106.6

a) See Explanatory Note 6, page 44. b) Includes coke plants and miscellaneous uses. c) Includes small quantities of anthracite shipped overseas to U.S. Armed Forces. d) Less than 0.05 million short tons. Quantities are included in the industrial sector. e) Preliminary.

U.S. Stocks of Coal by End-Use Sector, Year-End

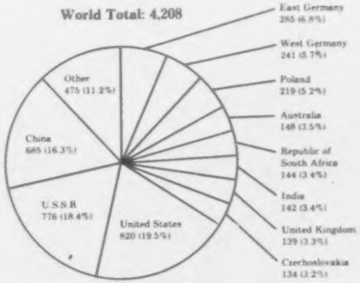
(Million Short Tons)

Year	Electric Utilities	Industrial[a]	Residential[b] and Commercial	Total
1960	51.7	22.8	0.7	75.2
1965	54.5	23.8	0.4	78.6
1970	71.9	20.8	0.3	93.0
1973	87.0	17.4	0.3	104.6
1975	110.7	17.3	0.2	128.3
1978	128.2	17.3	0.4	145.9
1979	159.7	21.9	0.3	182.0
1980	183.0	21.0	NA	204.0
1981	168.9	16.4	NA	185.3
1982[c]	181.1	15.1	NA	196.2

a) Includes stocks held at coke plants and by the transportation sector. b) Stocks at retail dealers. c) Estimated.

International Coal Production, 1981[a]

(Million Short Tons)



a) Preliminary.

U.S. Coal Prices

(Current Dollars per Short Ton)

Year	Bituminous Coal and Lignite: F.O.B.[a] Mines	C.I.F.[b] Electric Utility Powerplants	Anthracite Preparation Plants
1960	4.69	6.26	8.01
1965	4.44	5.71	8.51
1970	6.26	7.13	11.03
1973	8.53	9.01	13.65
1975	19.23	17.63	32.26
1978	21.78	23.75	35.25
1979	23.65	26.15	41.06
1980	24.52	28.76	42.51
1981	26.29	32.31	44.28
1982[c]	27.30	35.25	47.00

a) Free on board. b) Costs, insurance, and freight. c) Preliminary.

Note: During certain years, the average f.o.b. mine price exceeded the average c.i.f. electric utility price. This reflected long-term contract buying and occurred during a period of rapid and steep f.o.b. mine price increases.

Electricity

In 1982, electric utility generation in the United States totaled 2.2 trillion kilowatt-hours, representing the first decline in electricity generation since World War II. Conventional steam generation from fossil fuels was the major source of production, accounting for 73 percent of the total. Hydropower generated 14 percent, and nuclear power accounted for 13 percent. The remainder was generated from geothermal sources.

The mix of fossil fuels used to produce electricity has shifted over the past 30 years. Coal consumption has increased steadily until 1982 while petroleum and natural gas consumption have fluctuated. From 1972 through 1982, coal use at electric utilities increased 69 percent while petroleum consumption decreased 49 percent, and the use of natural gas dropped 19 percent. The use of petroleum to generate electricity during 1982 declined for the fourth consecutive year, to the lowest level since 1968. Regardless of the type of fossil fuel, the average thermal electric powerplant converts less than one-third of the energy content of consumed fuels into electrical energy for ultimate sale to end-users. The remaining energy is lost in the conversion process and in electricity transmission.

International[a] Nuclear Electricity Production

(Billion Gross Kilowatt-Hours)

	1971	1981	1982
North America	44.9	331.8	341.2
United States	40.8	288.5	298.6
Canada	4.2	43.3	42.6
Argentina	0	2.8	[b]1.9
Western Europe	51.3	293.4	321.8
Belgium	0	12.8	15.6
Finland	0	14.5	16.5
France	9.4	105.2	108.9
Germany, West	6.0	53.4	63.4
Sweden	0.1	37.7	38.8
Switzerland	1.9	15.2	15.0
United Kingdom	27.6	38.9	44.1
Other[c]	6.3	15.7	19.5
Far East	8.3	102.9	123.6
Japan	6.5	86.0	104.5
Taiwan	0	10.7	13.1
Other[d]	1.8	6.2	6.1
Total	104.5	730.9	788.5

a) Excludes centrally planned economies. b) Includes 54.1 million kilowatt-hours produced in Brazil. c) Includes Italy, the Netherlands, and Spain. d) Includes India, Pakistan, and South Korea.

Source: Nucleonics Week, McGraw-Hill Publishing Co.

Production of Electricity[a] by the U.S. Electric Utility Industry by Type of Energy Source

(Billion Kilowatt-Hours)

Year	Coal	Petroleum[b]	Natural Gas	Nuclear Power	Hydropower	Geothermal and Other[c]	Total
1960	403	46	158	1	146	(d)	754
1965	571	65	222	4	194	(d)	1,055
1970	704	184	373	22	248	1	1,532
1973	848	314	341	83	272	2	1,861
1975	853	289	300	173	300	3	1,918
1978	976	365	305	276	280	3	2,206
1979	1,075	304	329	255	280	4	2,247
1980	1,162	246	346	251	276	6	2,286
1981	1,203	206	346	273	261	6	2,295
1982[e]	1,193	147	305	283	304	5	2,242

a) See Explanatory Note 7, page 44. b) Includes distillate fuel oil, residual fuel oil (including crude oil burned as fuel), jet fuel, and petroleum coke. c) Includes production from plants that consume wood, refuse, and other vegetal fuels. d) Less than 0.5 billion kilowatt-hours. e) Preliminary.

Domestic Sales of Electric Utility Electricity to End-Use Sectors[a]

(Billion Kilowatt-Hours)

Year	Residential	Commercial	Industrial	Other	Total
1960	201	131	324	32	688
1965	291	200	429	34	954
1970	466	307	571	48	1,392
1973	579	388	686	59	1,713
1975	588	403	688	68	1,747
1978	674	461	809	73	2,018
1979	683	473	842	73	2,071
1980	717	488	815	74	2,094
1981	722	514	826	85	2,147
1982[b]	730	526	745	86	2,086

a) See Explanatory Note 8, page 44. b) Estimated.

U.S. Average Price of Electricity Sold by the Electric Utility Industry[a] to End-Use Sectors

(Cents per Kilowatt-Hour)

Year	Residential	Commercial	Industrial	Other	Weighted Average
1960	2.62	2.42	1.06	1.91	1.82
1965	2.39	2.18	1.00	1.82	1.70
1970	2.22	2.08	1.02	1.80	1.67
1973	2.54	2.41	1.25	2.10	1.96
1975	3.51	3.45	2.07	3.08	2.92
1978	4.31	4.36	2.79	3.62	3.69
1979	4.64	4.68	3.05	3.96	3.99
1980	5.36	5.48	3.69	4.76	4.73
1981	6.20	6.29	4.29	5.28	5.46
1982	6.86	6.86	4.95	5.92	6.13

a) Data 1979 and earlier are for Classes A and B privately-owned utilities only. Data 1980 and forward are for selected Class A utilities with electric operating revenues of $100 million or more in the previous year.

Source: Federal Energy Regulatory Commission.

The analysis presented on the following pages rests on a wide variety of assumptions which, taken together, represent a reasonable assessment of future world energy prices, economic conditions, and Federal energy programs. That analysis is therefore conditional--its accuracy depends upon the reliability of the underlying assumptions. The projections are not statements about what will happen in energy markets, but rather descriptions of likely futures based upon what is now known.

Since energy projections are highly sensitive to the assumed path of future oil prices, and since projected oil price paths are sensitive to certain economic and energy assumptions, a range of possible price paths are examined. The low, middle, and high price paths for world oil, presented in the following table, define a range of uncertainty with respect to the midprice case. They reflect only the general supply and demand pressures of the marketplace; the timing, duration, and depth of any future "price shock" is treated as a matter of chance and is considered here as a random event.

An important aspect of these price projections is the expected behavior of the Organization of Petroleum Exporting Countries (OPEC). Since 1974, OPEC prices have risen when world demand for OPEC oil approached 80 percent of OPEC's production capacity. OPEC has tended to raise prices sharply whenever demand approaches production capacity but lower them only moderately when demand falls. Projected falling oil prices for the next few years are caused by the current 9 to 10 million barrel per day excess in world oil production capacity and the near term outlook for relatively weak economic growth worldwide.

The economic growth and behavior of the world's economy is another factor that has significant effects on energy. The average annual growth in real gross domestic product from 1980 through 1990 is assumed to be 2.6 percent for the free world as a whole, 2.4 percent for the industrial countries of the OECD, and 3.3 percent for the developing countries. The relatively low growth rates projected for the 1980's reflect assumptions about reduced economic performance in the near term and a rather weak recovery over the last half of the decade. [Projected economic growth rates are based on the Hudson-Jorgenson and Data Resources, Inc. macroeconomic models of the United States and on a Wharton EFA, Inc. forecast extended to 1990 and adjusted to account for preliminary world oil price projections.]

Free World Oil Prices, 1979-2000

Year	Real 1982 Dollars per Barrel		Nominal Dollars per Barrel[a]	
	Midprice Case	Uncertainty Range	Midprice Case	Uncertainty Range
1979	27	--	22	--
1980	39	--	34	--
1981	39	--	37	--
1982	34	--	34	--
1983	30	28 - 32	31	29 - 32
1984	26	23 - 30	29	25 - 33
1985	25	21 - 34	29	24 - 40
1986	28	21 - 38	34	26 - 47
1987	32	22 - 41	42	29 - 54
1988	34	24 - 43	48	34 - 60
1989	36	26 - 45	54	39 - 67
1990	37	28 - 48	59	45 - 77
2000	59	42 - 85	--	--

[a] Inflation rates based on projections developed using the DRI macroeconomic model.

International Projections

Total energy consumption in the free world is projected to increase during the rest of this decade, rising from about 200 quadrillion Btu in 1980 to about 230 quadrillion Btu in 1990. Although all regions of the free world contribute to the increase the fastest rates of growth are expected in the OECD Pacific and the developing countries: by 1990, energy consumption in those regions is projected to increase by about 20 percent and 36 percent, respectively, from 1980 levels. Relatively rapid growth is also expected in other partly or newly industrialized countries such as Mexico, Brazil, South Africa, and Hong Kong, given the resolution of near-term debts. Consumption in the industrialized countries is expected to be dampened by increased energy efficiency and conservation. Though energy consumption in North America is expected to grow at a slower rate, its share will remain large: 43 percent in 1980 and 41 percent in 1990.

Oil consumption is projected to grow again in absolute terms in 1984, but its share of total consumption is expected to decline during the 1980's. Oil price increases caused by the 1973 Arab oil embargo and the 1979 Iranian revolution provided incentives among the oil-importing countries to improve energy efficiency and to switch to other fuels where possible. The resulting drop in oil consumption, continued slow economic growth in industrialized countries, and growing difficulties in international financial markets are expected to keep oil markets soft in the near term, dampening both consumption and prices. As the following table shows, little change in oil consumption is projected for the industrialized OECD countries through 1990, implying greater energy efficiency and fuel switching. In contrast, oil consumption in the developing countries is projected to grow steadily, and is likely to exceed that of Western Europe in 1983.

OPEC oil production is expected to rise from its 1982 rate of 20 million barrels per day to about 27 million barrels per day by 1990--still well below the 1977 peak of 31 million barrels per day. Production by developing countries is expected to rise about 34 percent during the 1980's; OECD production is expected to remain relatively stable. Additions to liquid fuel supplies can be expected from enhanced oil recovery, shale oil, and synthetic liquids, but not in significant quantities until sometime in the 1990's.

Free World Oil Consumption and Production,[a] History and Projections[b]

(Million Barrels per Day)

	1960	1973	1981	1985 Prices			1990 Prices		
				High	Mid	Low	High	Mid	Low
World Oil Price (1982 dollars per barrel)	8.69	8.00	39.27	34.00	25.00	21.00	48.00	37.00	28.00
Consumption	19.2	49.2	47.4	46.7	50.8	53.8	46.3	52.8	61.3
United States[c]	9.8	17.6	16.5	16.1	18.4	20.1	14.1	17.4	21.7
Canada	0.8	1.7	1.8	1.8	1.9	1.9	1.8	2.0	2.3
Japan	0.7	5.1	4.8	4.6	4.9	5.0	4.7	5.3	6.1
OECD Europe	4.5	15.2	12.6	12.0	12.8	13.4	11.6	13.5	16.0
OPEC	0.7	1.9	2.8	3.2	3.2	3.2	3.9	3.9	3.9
Other Countries[d]	2.4	7.0	8.9	9.1	9.7	10.1	10.2	10.7	11.3
Production	19.0	48.9	45.5	49.0	50.1	53.1	46.1	52.6	61.0
United States	8.1	11.4	10.7	10.8	10.6	10.4	11.0	10.0	9.1
Canada	0.3	2.1	1.6	1.5	1.5	1.5	1.7	1.7	1.6
OECD Europe	0.3	0.5	2.8	3.4	3.4	3.4	3.1	3.0	2.8
OPEC	6.7	31.3	23.7	21.5	25.8	29.0	19.7	27.7	37.7
Other Countries[d]	1.1	2.6	6.7	8.8	8.8	8.8	10.5	10.2	9.9
Net Exports from CPE[e]	0.4	0.9	1.2	1.0	1.0	1.0	0.5	0.5	0.5
Stock Change	-0.3	-0.5	-0.7	0.3	0.3	0.3	0.3	0.3	0.3

a) Includes crude oil and natural gas liquids. United States includes other hydrocarbons, hydrogen, and refinery gains. b) Derived using assumptions under the midprice case, except for world oil prices. c) Includes Puerto Rico, Virgin Islands, and purchases for the Strategic Petroleum Reserve. d) Excludes Centrally Planned Economies. e) Centrally Planned Economies.

Domestic Projections

Trends in fossil fuel supplies are expected to be mixed throughout the remainder of the 1980's. Coal production is projected to rise from 19.2 quadrillion Btu in 1980 to about 23.9 quadrillion Btu by 1990. In contrast, domestic oil production is projected to remain relatively stable, declining slightly by 1990. Net imports of crude oil and petroleum products are expected to rise from 4.2 million barrels per day in 1982 to 7.1 million barrels per day by 1990. Natural gas production is projected to decline through the middle of the decade before rising during the late 1980's.

The domestic oil market has been characterized in recent years by increased drilling activity, stable production, and declining imports and consumption. These trends are likely to change in the near future: domestic drilling is likely to reflect last year's reduction in active rigs as well as the lower oil prices that are expected in the next few years. The declines in imports and consumption are likely to reverse as the economy recovers. The key determinants of future oil supply are the deposits remaining to be discovered, the level of drilling activity, the rate at which reserves are produced via conventional means, and future use of enhanced oil recovery techniques.

Total natural gas supply (production plus imports) is expected to decline from 20.5 trillion cubic feet (Tcf) in 1980 to 15.5 Tcf in 1986, then rise to 17.2 Tcf by 1990. (One major assumption of these forecasts is that the Alaskan natural gas pipeline will not be in service by 1990.) Since old reserves will continue to be depleted, new reserves (those developed after 1978) must supply proportionately more. New gas, which contributed about 16 percent of production in 1980, is expected to increase to 42 percent of production in 1985 and 69 percent by 1990. Future production must come largely from newly discovered deposits, which are likely to be deeper and smaller, and thus more expensive to develop.

The driving force behind coal production is its relatively low price. Additionally, the environmental advantages of low-sulfur coal will cause a regional shift in mining location--most of the Nation's low-sulfur coal is located in the West. By 1990, 36 percent of production is expected to come from western States. Total production is projected to grow by 2.7 percent annually through 1990.

U.S. Energy Supply, Midprice Case 1982-1990

(Quadrillion Btu)

	1982	1983	1984	1985	1986	1987	1988	1989	1990
Production	64.2	63.7	63.9	63.2	63.9	65.0	66.8	68.2	69.1
Petroleum	20.6	20.5	20.6	20.4	20.5	20.5	20.5	20.3	19.3
Natural Gas . . .	18.2	17.5	17.0	15.2	14.7	14.8	15.3	15.9	16.4
Coal.	19.1	19.4	19.4	20.3	20.8	21.4	22.0	22.8	23.9
Nuclear	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3
Hydro	3.3	^{a}3.2	^{a}3.1	^{a}3.1	^{a}3.1	^{a}3.2	^{a}3.2	^{a}3.2	^{a}3.2
Net Imports	7.3	8.6	12.3	14.8	14.6	13.7	12.7	12.2	12.9
Crude Oil	6.8	7.5	10.4	13.0	12.7	12.0	11.4	11.0	11.9
Other Petro . . .	2.1	2.5	3.0	3.1	3.1	3.1	3.1	3.1	3.2
Natural Gas									
Contracted^{b} . .	0.9	1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Other^{c}.	0	0	0	0	0.3	0.2	0	0	0
Coal and Coke . .	-2.8	-2.6	-2.7	-2.9	-3.0	-3.2	-3.4	-3.6	-3.8
Electricity . . .	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4
SPR^{d} Additions . .	-0.4	-0 4	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
Stock Withdrawals .	-0.2	0	0	0	0	0	0	0	0

a) Includes geothermal and other. b) Includes pipeline gas and liquefied natural gas. c) Additional gas imports. d) Strategic Petroleum Reserve.

Total energy use is projected to rise modestly through 1990. In the near term, this is based on economic recovery and relatively stable world oil prices, in later years, modest growth in personal income, industrial activity, and population contribute. The shares of total energy consumed by each sector are projected to change through 1990. In particular, the industrial sector will account for a greater share of energy use, largely because fuel is used both for heat and power and as direct raw material, and because of the effects of economic growth on industrial energy use.

Since most of the housing stock that will be present in 1990 already exists, little change in residential energy use is expected. Half of this energy use is projected to be for space heating by 1990, down from 54 percent in 1980. Although natural gas is projected to remain the major residential fuel through 1990, its actual consumption and relative share are expected to fall, to 4.4 quadrillion Btu and 47 percent, respectively. The high price of oil is expected to result in lower use, and a decline in its relative share to 14 percent of residential consumption (1.3 quadrillion Btu). A substantial increase in real energy prices is expected to cause average per-household energy use to drop at a yearly rate of 1.6 percent through 1990, to 99 million Btu per household at the end of the decade. Expressed in 1982 dollars per million Btu, residential fuel prices are projected to increase from an average of $8.33 in 1980 to $11.74 in 1990. Total transportation fuel use is projected to decline by 14 percent between 1980 and 1990; light vehicle miles-per-gallon is expected to rise 4.5 percent annually during the rest of the decade while gasoline consumption declines 26 percent.

Commercial energy use is projected to increase by 16.5 percent from 1980 to 1990; electricity is expected to replace natural gas as the primary fuel, while energy use per square foot declines. Industrial energy use is projected to grow at 0.2 percent annually; electricity is expected to increase its market share (growing 3.2 percent annually) due to its price stability relative to oil and gas. Coal use is projected to grow 1.1 percent yearly through 1990.

Total electricity demand is projected to grow about 4 percent annually through 1990. Nuclear's share of generation is expected to rise from 13 percent in 1980 to 19 percent in 1990. Coal's share is expected to drop slightly, to 51 percent by 1990 (although, in aggregate, overall coal use will increase substantially). Environmental regulations are expected to cause a gradual shift from Eastern high-sulfur coal to Western low-sulfur coal.

U.S. Energy Consumption, Midprice Case 1982-1990
(Quadrillion Btu)

	1982	1983	1984	1985	1986	1987	1988	1989	1990
Electric Utility Fuel	24.3	24.7	26.0	27.2	28.1	29.1	30.1	31.0	32.2
Petroleum	1.8	1.5	2.9	4.1	4.2	4.2	4.2	4.0	4.0
Natural Gas	3.3	3.4	2.7	1.7	1.7	1.7	1.9	2.2	2.4
Coal.	12.7	13.2	13.5	14.2	14.5	14.8	15.1	15.6	16.3
Nuclear	3.0	3.2	3.7	4.1	4.7	5.3	5.8	6.1	6.3
Hydropower, Geothermal, and Other	3.5	3.4	3.4	3.5	3.5	3.5	3.5	3.5	3.6
Non-Electric Utility Fuel.	46.4	47.0	48.4	49.0	48.6	48.1	47.8	47.8	48.2
Petroleum	28.6	29.2	30.7	32.1	31.8	31.2	30.6	30.3	30.3
Natural Gas	15.0	14.9	14.5	13.7	13.5	13.5	13.7	13.9	14.1
Coal.	3.0	2.9	3.2	3.3	3.3	3.4	3.5	3.7	3.8
Total Consumption . .	70.7	71.7	74.5	76.3	76.9	77.2	78.0	78.9	80.5

Gross National Product (GNP) Implicit Price Deflators, 1972=100

The Implicit GNP Price Deflator is a measure of the change in U.S. price levels over time--the ratio of the current value of goods and services to the base year value for the same goods and services. In this report, the base year is 1972. Following are Deflator values that can be used to convert the current-dollar data in this report to constant-dollar data.

1960 - 68.70
1965 - 74.36
1970 - 91.45
1973 - 105.75
1975 - 125.79

1978 - 150.42
1979 - 163.42
1980 - 178.64
1981 - 195.51
1982 - 207.15

Thermal Conversion Factors, 1982[a]

(Approximate Heat Content of Various Fuels)

Petroleum		
Crude Oil Production . . .	5.8	million Btu/barrel
Refined Petroleum Products Consumption, Average . .	5.448	million Btu/barrel
Natural Gas Plant Liquids Production	3.930	million Btu/barrel
Natural Gas, Dry		
Production	1,015	Btu/cubic foot
Consumption, Average . . .	1,027	Btu/cubic foot
Bituminous Coal and Lignite		
Production	22.38	million Btu/short ton
Consumption, Average . . .	21.80	million Btu/short ton
Electricity		
Conversion Heat Rates		
Nuclear Power	10,908	Btu/kWh
Hydropower.	10,388	Btu/kWh
Geothermal Power.	21,594	Btu/kWh
Electricity Consumption . . .	3,412	Btu/kWh
Hardwood (Dry).	8,000- 9,000	Btu/pound

a) Preliminary.

Explanatory Notes

1. Primary Energy Production--International. Includes only crude oil and lease condensate, natural gas plant liquids, dry natural gas, coal, and electricity from hydropower and nuclear power. Crude oil production is measured at the wellhead and includes lease condensate. Dry natural gas production is the amount of natural gas production that is available to be marketed and consumed as a gas. Coal production is the sum of sales, mine consumption, issues to miners, and issues to coking, briquetting, and other ancillary plants at mines. Coal production data include quantities extracted from surface and underground workings and normally exclude wastes removed at mines or associated preparation plants. Electricity production from hydropower and nuclear power includes both electric utility and industrial production reported on a net basis, thus excluding electricity that is generally used by the electric powerplant for its own operating purposes or electricity losses in the transformers that are considered integral parts of the station.

2. Energy Production and Consumption. Data do not include small quantities of energy forms for which consistent historical data are not available, such as solar energy obtained by the use of thermal and photovoltaic collectors; wind energy; and geothermal, biomass, and waste energy other than that consumed at electric utilities.

3. Fossil Fuel Resources. Crude oil and natural gas: Resources currently known and in production are defined as proved reserves. Reserves known to be producible with secondary recovery techniques are classified as indicated reserves. Inferred reserves are known to exist based on geological information but are not yet developed and thus do not contribute to current production. Undiscovered recoverable resources are those quantities which are as yet undiscovered, but which are thought to exist in favorable geologic settings. Coal: Demonstrated coal reserves are measured and indicated deposits in place. These are coal resources for which definitive physical measurements have been made. That portion of the demonstrated reserve base which can technically, economically, or legally be recovered is defined as recoverable reserves. Estimated recoverability of demonstrated coal reserves ranges from 40 to more than 90 percent at current prices. Additional coal resources are known to exist; however, quantities of

coal already located are so large that no systematic effort is made to account for all of these reserves.

4. Refined Petroleum Product Supplied. Total refined petroleum products supplied is the sum of each refined petroleum product supplied. For each product the amount supplied is derived by summing production, imports, and net withdrawals from primary stocks and subtracting exports. This term is synonymous with the term "Refined Petroleum Product Consumption" in the Overview section.

5. Natural Gas Consumption. Natural gas consumption statistics are compiled from a survey of natural gas producing, transmission, and distribution companies, and electric utility companies. Consumption by end-use sector from these surveys is compiled on a national and individual State basis and then balanced with national and individual State supply data.

6. Coal Consumption. Data in this report on the consumption of bituminous coal, lignite, and anthracite are generated primarily from consumption data reported in surveys. Included are data reported by all powerplant companies, all coke plant companies, approximately 75 percent of the industrial and large commercial establishments, and approximately 25 percent of the retail dealers. Remaining data for the industrial and large commercial establishments are estimated based on factors updated every 5 years [illegible] Census of Manufacturers, a Bureau of the Cens[illegible]lication. The remaining data on retail dealers [illegible] based on the balance of supply and disposition.

7. Production of Electricity. Data on the [illegible]tion of electricity in the United States represe[illegible] gross electricity output measured at the generator terminals, minus powerplant use (net electricity generated). International nuclear electricity production data are gross electricity output.

8. Electricity Sales. Data on sales of electric utility electricity represent gross electricity output measured at the generator terminals, minus powerplant use and transmission and distribution losses.

9. Reclassified. Accurate calculation of the quantity of petroleum products supplied is complicated by recycling and renaming of products, and their receipt from outside the primary supply system. An adjustment, termed "Reclassified," is made to correct this accounting problem. Including only unfinished oils and gasoline blending components, it is the sum of the net changes in primary stocks (net withdrawals is a plus quantity; net additions is a minus quantity) plus imports minus net input to refineries.

Glossary

Base Gas. The total volume of natural gas in underground storage reservoirs that will maintain the required rate of delivery during an output cycle.

British Thermal Unit (Btu). The amount of energy required to raise the temperature of 1 pound of water 1 degree Fahrenheit at or near 39.2 degrees.

Housing Unit. A structure or part of a structure in which a group of fewer than 11 unrelated persons lives (or could live) as their permanent place of residence. Excluded are group quarters such as prisons, hospitals, nursing homes, dormitories, fraternity/sorority houses, and convents. Hotel and motel rooms are included if permanently occupied by one household.

Lease Condensate. A natural gas liquid recovered from gas-well gas in lease separators or field facilities. It consists primarily of pentanes and heavier hydrocarbons. Generally, it is blended with crude oil for refining.

Liquefied Gases. Propane, propylene, butane, butylene, ethane-propane mixtures, and isobutane produced at refineries or natural gas processing plants, including plants that fractionate raw natural gas plant liquids.

Marketed Natural Gas Production, Including Nonhydrocarbon Gases. This quantity is derived. It is gross withdrawals of natural gas from producing reservoirs, less gas used for reservoir repressuring and quantities vented and flared. It includes the nonhydrocarbon gases subsequently removed.

Native Gas. The total volume of natural gas indigenous to the storage reservoir at the time the gas storage started.

Natural Gas Liquids. Products obtained from lease separators, field facilities, and natural gas processing plants. Natural gas liquids include natural gas plant liquids and lease condensate.

Natural Gas Plant Liquids. Products obtained from processing natural gas at natural gas processing plants, including natural gasoline plants, cycling plants, and fractionators. Products obtained include ethane, liquefied petroleum gases (propane, butanes, propane-butane mixtures, ethane-propane mixtures, and isobutane), isopentane, natural gasoline, unfractionated streams, plant condensate, and minor quantities of other finished products such as motor gasoline, special naphthas, jet fuel, kerosene, and distillate fuel oil.

The Natural Gas Market Through 1990

An Analysis of the
Natural Gas Policy
Act and Several
Alternatives, Part IV

May 1983

Energy Information Administration
Office of Oil and Gas
U.S. Department of Energy
Washington, D.C. 20585

Prepared by:
Richard P. O'Neill
William G. Kurator
Barbara Mariner-Volpe
William A. Trapmann
Paul Dickens
John Herbert
Joan Heinkel
Ruth Stokes
Reginald Sanders
Alan Tawshunsky
Charles Mylander
Thomas Mooney
Ronald Earley
Christoph Witzgall
Lambert Joel
Patsy Saunders
Betsy O'Brien

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CONTACTS

General information for this report may be obtained from Jimmie L. Petersen (202/252-6401), Director of the Office of Oil and Gas, and Diane W. Lique (202/252-6090), Director of the Reserves and Natural Gas Division, Energy Information Administration.

Specific information regarding the preparation or contents of this publication may be obtained from Dr. Richard P. O'Neill (202/252-4680), Chief of the Analysis and Forecasting Branch. Information on specific major portions of this technical report may be obtained from the following:

- Supply Analysis - William Trapmann (202/252-9602) and Barbara Mariner-Volpe (202/252-4749).
- Gas Analysis Modeling System (GAMS) Development - Dr. Chris Witzgall and Patsy Saunders of the National Bureau of Standards (202/921-3855); Dr. Charles Mylander (301/267-2300) and William Stewart (301/454-3471); William Kurator (202/252-6408), Barbara Mariner-Volpe, Alan Tawshunsky (202/252-6127), Joan Heinkel (202/252-4838); and Sam Cohen (202/252-2394).
- Demand Analysis - Thomas Mooney (202/252-1463) and Dr. Mark Rodekohr (202/252-6574); Betsy O'Brien (202/252-9855); Reginald Sanders (202/252-1466) and John Herbert (202/252-6131).
- Macroeconomic Impact Analysis - Ronald Earley and William Curtis (202/252-1455).
- Distribution Impact Analysis - Gerald Peabody (202/252-1122).
- Analysis of Alternative Scenarios - Richard O'Neill, Paul Dickens (202/252-5243), and Joan Heinkel.
- Analysis of Contract Escalation Clauses and Impact on Prices - Joan Heinkel and Ruth Stokes (202/252-4725).

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PREFACE

This is the fourth report in a planned, comprehensive, and ongoing study by the Energy Information Administration (EIA) relative to an analysis of the Natural Gas Policy Act of 1978 (NGPA) and several possible alternatives. Part I, which presented a wide variety of information on the current state of the natural gas market, was published in December 1981 [1]. Part II, which analyzed pricing provisions and take-or-pay provisions in selected natural gas producer/purchaser contracts, was published in June 1982 [2]. Part III, which analyzed the Purchased Gas Adjustment filings over the past several years of twenty major interstate pipelines, was published in September 1982 [3].

The EIA will continue to analyze and publish reports on selected aspects of the natural gas market, using the results and techniques developed through this study.

EXECUTIVE SUMMARY

Few topics affect the broad spectrum of American energy interests as does "natural gas deregulation." While Federal regulation of the natural gas industry began with the passage of the Natural Gas Act of 1938, numerous laws and regulations passed over the succeeding 40 years have affected all aspects of the natural gas industry. The Natural Gas Policy Act of 1978 (NGPA) is one of the most far-reaching of these laws.

This report is the fourth in a study of the NGPA, in which the Energy Information Administration (EIA) seeks to provide information and analysis describing the effects of the NGPA and proposed changes. It presents an analysis of natural gas wellhead price deregulation, comparing the projected results under the current NGPA decontrol schedule with those under three alternatives: the Administration proposal, entitled the "Natural Gas Consumer Regulatory Reform Amendments of 1983"; an alternative phased decontrol; and continuance of the current NGPA price ceilings indefinitely. The possible consequences of the alternative policies through 1990 are discussed along with the impacts of key assumptions on the NGPA projections. The four cases in this report are specified in Table ES1.

Those associated with the downstream market, that is, the distributors and the consumers, generally favor the regulation of wellhead prices. The continued controls case extends price controls indefinitely. Most producers and some groups representing large industrial users favor wellhead price decontrol. The Administration proposal effectively allows all gas to be deregulated by 1985 by allowing any party to a contract to abrogate the contract if it is not renegotiated prior to January 1, 1985, while the phased decontrol case raises price ceilings on all gas until 1985 when all gas is decontrolled. Pipeline companies have expressed concern over the potential "fly-up" in the wellhead price when gas is decontrolled.

Background

Since the early 1970's, when it became clear that Federal wellhead price controls were seriously affecting the gas market, there has been considerable discussion over the appropriate remedy. The NGPA, a compromise that evolved over 18 months of Congressional debate, was the first comprehensive natural gas legislation since the passage of the Natural Gas Act in 1938. The NGPA was intended to bring the intrastate market under Federal price ceilings at the wellhead, then to remove a large portion of both interstate and intrastate price ceilings (mostly on more recently discovered gas) by 1985. This has become known as partial deregulation.

Since most natural gas sells at the wellhead under long-term contracts, the perturbations in the natural gas market over the past 20 years are reflected in vast differences in the prices, quantities, and terms of existing contracts. For example, the current wellhead price varies from below $0.30 per million Btu (MMBtu) to above $9 per MMBtu -- a 30-fold difference. When gas arrives at the burner-tip, the purchaser in most cases pays a price based on the seller's average purchase cost of the gas plus a charge for transmission and distribution. This practice and the existing nature of gas purchase contracts in the downstream interstate natural gas market raise the question of whether the wellhead market and the burner-tip market communicate price signals in a manner to enable timely market adjustments. Without proper market adjustments consumers can pay much more than is necessary for natural gas.

Currently, the wellhead market is very "soft." In early 1981, new deep gas contracts, which can be viewed as indicators of the market, were receiving wellhead prices greater than $9 per MMBtu. However, by late 1981 and early 1982, a turnaround appears to have taken place. At least five pipeline companies exercised "market-out" clauses (that is, contract clauses that allowed the pipeline to reduce the price it was paying for gas with the possibility of losing the reserves under contract) for some of their high-cost gas. Although market adjustments are taking place, some gas under existing contracts still gets over $9 per MMBtu.

In 1982 natural gas delivered to consumers was down 8 percent from 1981 with a considerable amount of potential production "shut-in." Over 80 percent of the decline was in industrial consumption of natural gas which declined by a dramatic 17 percent from 1981 to 1982.

Pending Legislation

At least 5 bills on natural gas issues have been introduced in the Senate and 7 bills in the House of Representatives. Perhaps the most significant impact of the various legislative proposals is on natural gas contracts. The Administration's proposal is based on the theory that a wellhead market free from Federal regulations will function in ways that will efficiently deliver gas to end-use customers. That is, after the transition period there will be no Federal resticticons (except management responsibility for Federal lands and waters) on natural gas contracts. Implicitly, the legislation assumes that current market conditions or similar ones will not reappear, because if unrestricted, the market will adjust long before the situation becomes serious.

The Gephardt bill permanently eliminates commodity-based price escalation but does not specifically rule out periodic renegotiations. Contracts calling for periodic renegotiation were more frequently found in intrastate pipeline contracts prior to the NGPA. Additionally, pipelines can apparently have price escalators tied to the bill's price adjustment which is commodity-based. The Addabbo bill eliminates all but definite price escalation. Without flexibility to adjust prices both up and down to reflect market conditions, contracts may become very short-term, creating financing problems for both producers and purchasers.

Decontrol dates also differ among proposals. The Addabbo bill does not change the dates for lifting of price ceilings, but by eliminating indefinite escalators and reducing take-or-pay, defuses the "fly-up" for old contracts, although not for new contracts. The Slattery bill removes the price ceilings on some gas immediately upon enactment leaving most to the NGPA schedule. The Gephardt bill moves dates for lifting price ceilings back 2 years but continues restrictions on contract provisions indefinitely. The Administration's bill starts total decontrol upon enactment and completes it by January 1, 1986.

In almost all proposals there are incentives for increased contract carriage of gas by pipelines. If there were no authorization delays, transaction costs or general fear of engaging in different practices, the Administration's bill would likely make pipelines contract carriers, "marketing out" of old contracts and negotiating new contracts to carry the gas. Additional profits of over a billion dollars are potentially available to the pipelines under this option. Under the Bradley bill, the burden of proof for not carrying is on the pipeline with economic incentives to voluntarily carry the gas. Under the Gephardt bill, the Federal Energy Regulatory Commission orders contract carriage, but pipelines have no guarantee of doing better since the compensation is determined by the Commission under the NGA.

Under the Slattery bill the scope is more limited and requires more consideration at the Commission raising the potential for long lags. In general the Commission's authority increases under the Slattery, Gephardt, and Addabbo proposals and decreases under the Administration's proposal. The requirement of contract carriage creates incentives for the evolution of spot and futures markets for natural gas and direct sales to large industrial companies, electric utilities, and distributors.

For this analysis cases which represent existing law (NGPA Reference Case), two generic alternatives (Phased Decontrol Case and Continued Controls Case) which embody many of the key features of current legislative proposals, and the Administration's Proposal Case, which includes the key elements of the "Natural Gas Consumer Regulatory Reform Amendments of 1983" have been selected. Using these analyses as a foundation, EIA plans to examine other current legislative proposals in the near future.

Table ES1. Overview of Legislative and Policy Alternatives

NGPA Reference Case	NGPA price paths and decontrol schedule.
Administration Proposal Case	Ceiling price is the lower of the NGPA ceiling or "average" new free market price (gas cap) until deregulation on January 1, 1986. Price regulations are removed from any new contracts or renegotiated contracts. On January 1, 1985, for any contract that has not been renegotiated, either party may exercise a "market-out". Take-or-pay requirements limited to 70 percent of deliverability. Incremental pricing (Title II) and the Fuel Use Act gas provisions are repealed.
Phased Decontrol Case	Increase from NGPA price ceilings to 70 percent of refiner's acquisition cost of oil[1] for all gas by January 1, 1985. The price ceiling for Section 107 wells is 70 percent of refiner's acquisition cost of oil as of January 1, 1983. All price regulations are removed as of January 1, 1985.
Continued Controls Case	NGPA price paths; no decontrol in 1985 (i.e., repeal of Section 121). Gas continues to be priced by Title I formulas. Section 107 gas now free from controls remains free from controls.

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[1] For this study, the refiner's acquisition cost of oil and the world oil price are assumed to be the same.

Methodology

The analysis in this report is based on a simulation of the natural gas market, taking into consideration projected new discoveries, contract purchases of reserves, the current natural gas contract pricing and take-or-pay provisions for production purchases, the gas supplies currently dedicated to pipeline companies, cost-of-service pricing by pipeline companies and distributors, the regional markets with six-sector detail, and the projected market sector demand.

This approach differs considerably from those used in previous studies by the EIA and others, in that explicit recognition is given to the fact that there are two distinct, but loosely coupled, markets for natural gas. In the first, pipeline systems acquire reserves of natural gas under long-term contracts to satisfy current and projected demand. In the second, production of natural gas from the reserves is sold and delivered to ultimate consumers.

The history of natural gas markets indicates that shortages arise from time to time in both interstate and intrastate markets. Rather than discussing the specific implications of projected shortages, the analysis in this report uses the concept of a "supplemental source" of energy to absorb any shortfalls. This supplemental source, which is assumed to be available in unlimited quantities at a price equal to 130 percent of the price of No. 2 fuel oil, may be viewed as a combination of the following: spot market purchases, synthetic gas, imports, load loss to other energy sources, and curtailments. The detail of which and how much of each is used is beyond the scope of this analysis and may be different for different pipeline systems and regions of the country.

Wellhead Prices

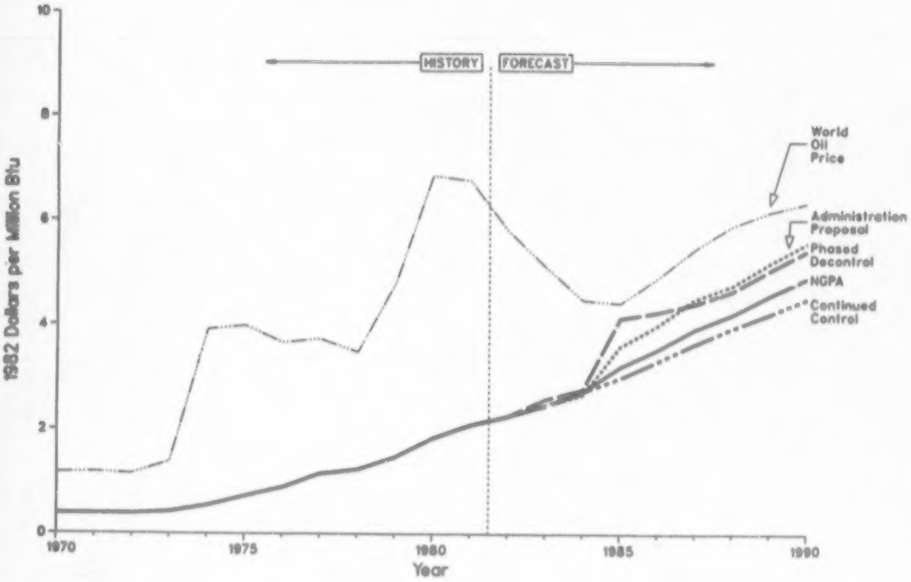
As shown in Figure ES1, the average wellhead price under the NGPA is projected to increase at less than the rate of the past few years through 1984. With the decontrol of many categories of gas in 1985, there is a 17 percent projected price fly-up followed by a return to a 9 percent per year real price increase through 1990. By 1990, the average wellhead purchase price is $4.88 per MMBtu (in 1982 dollars), and roughly 20 percent of the flowing gas is still under controls. However, the price of gas under new contracts is about $6 per MMBtu (see Table ES2), reflecting expectations of demand beyond 1990.

Under continued controls, average wellhead prices are projected to rise steadily through 1990 without the 1985 price fly-up which characterizes the NGPA case. By 1990 the average price is 8 percent below the NGPA price, although the new contract price for the small volume of decontrolled gas is significantly higher than for similar gas under the NGPA.

Under phased decontrol, the wellhead price rises faster than under the other cases. Wellhead prices rise under a formula which would bring the price to 70 percent of the world oil price by 1985, then all price ceilings are removed in 1985. There is still a considerable fly-up due to contract price escalation provisions in 1985 as all controls are removed. By 1990, the average price is 11 percent higher than under the NGPA, although the new contract price is about the same.

Under the Administration proposal case, prices are lower in 1984 as compared to the NGPA due to the gas cap pricing mechanism. In 1985 the average wellhead price is higher than under the NGPA, due to the decontrol of all gas. By 1990, the average wellhead price is 14 percent higher, but the new contracts price is 9 percent lower compared to the NGPA case because there is no cushion effect of low cost gas.

Figure ES1. Average Wellhead Price Under the NGPA and Alternative Policies



Source: Historical data, Annual Report to Congress 1981, Table 51, p. 115; forecast data, Gas Analysis Modeling System.

Table ES2. Summary of Natural Gas Regulation Alternatives

	Actual	NGPA Reference		Administration Proposal		Phased Decontrol		Continued Controls	
	1981	1985	1990	1985	1990	1985	1990	1985	1990
Supply Outlook									
Reserves (dry), excluding Alaska (Quads) ..	173.2	161.8	153.4	161.9	151.7	164.2	156.1	161.6	155.3
New Discovery Reserve Additions, cumulative for the preceeding 5-year period (Quads)	78.4	77.8	78.6	77.9	73.4	78.4	74.5	77.8	82.5
Marketed Production, excluding Alaska (Quads)	20.2	18.4	18.4	18.1	17.7	16.8	17.7	18.6	18.8
Reserves-to-Production Ratio	8.6	8.8	8.3	8.9	8.6	9.8	8.8	8.7	8.3
Supplemental Supplies (Quads)	0.2	0.1	0.2	0.1	0.0	0.0	0.0	0.2	0.4
Supply Prices (1982$/MMBtu)									
Average Wellhead Price	2.04	3.19	4.88	3.58	5.56	4.11	5.41	2.98	4.49
New Deregulated Contract Price	9.00	4.87	6.55	4.38	5.96	4.21	6.44	11.17	13.54
World Oil Price	6.76	4.42	6.36	4.42	6.36	4.42	6.36	4.42	6.36
Delivered to Consumers (excluding Alaska)									
Total									
Quantity (Quads)	18.2	16.8	16.9	16.5	16.1	15.4	16.1	17.1	17.4
Price (1982$/MMBtu)	3.63	5.14	7.28	5.49	7.89	6.14	7.76	4.97	6.94
Residential									
Quantity (Quads)	4.7	4.7	4.5	4.7	4.4	4.6	4.4	4.8	4.6
Price (1982$/MMBtu)	4.43	6.11	8.35	6.48	8.96	7.14	8.87	6.01	8.05
Average Household Expenditures for Natural Gas (1982$/per Year)	476	605	743	647	779	675	791	597	722
Industrial									
Quantity (Quads)	7.3	6.2	6.4	6.0	6.0	5.7	6.0	6.3	6.8
Price ($1982/MMBtu)	3.25	4.59	6.65	4.91	7.23	5.50	7.12	4.38	6.31
Macroeconomic Effects									
Real GNP (Trillions of 1972 Dollars)	1.50	1.64	1.90	1.64	1.90	1.64	1.89	1.64	1.90
Consumer Price Index (1967 = 100)	272	332	466	333	471	472	472	331	464
Unemployment Rate (Percent)	7.6	8.3	7.5	8.3	7.5	8.4	7.5	8.3	6.7

Source: 1981 reserve quantities are from U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1981 Annual Report, DOE (EIA-0216(81)), August 1982.
1981 production, consumption and price are from the Natural Gas Annual 1981.
1981 macroeconomic and world oil price data are from the 1982 AEO.
1981 prices have been converted to 1982 dollars based on Table B2.
World oil price projections are from the 1982 AEO.
Projections of macroeconomic effects are from simulations using the DRI macroeconomic model.
All other projections are from the Gas Analysis Modeling System.

Production

Production of natural gas, shown in Figure ES2, is determined both by demand and by wellhead prices. Thus the higher prices under phased decontrol and the Administration proposal case lead to lower production because of lower demand. Similarly, the lower prices under continued controls encourage more consumption and consequently higher production in the early years of the forecast period, although production falls after 1987 as the disincentive of lower prices becomes dominant.

While purchases of "supplemental energy" are virtually non-existent under phased decontrol and the Administration proposal case, some is needed under the NGPA and large amounts are needed under the low prices of the continued controls case to account for the shortfall between production and demand.

Reserves

Exploration for and development of new natural gas reserves depends upon the "marginal" wellhead price, that is, the price for new contracts, rather than upon the average wellhead price. Reserve levels under the four cases are shown in Figure ES3. Under the Administration proposal case, the reduced ability to roll in new gas prices leads to essentially the same reserve margins as under the NGPA.

Although the marginal wellhead price for new decontrolled gas is very much higher under continued controls than under the NGPA, relatively little gas is eligible for this price. At a marginal price over double that of the NGPA there is little change in the reserves.

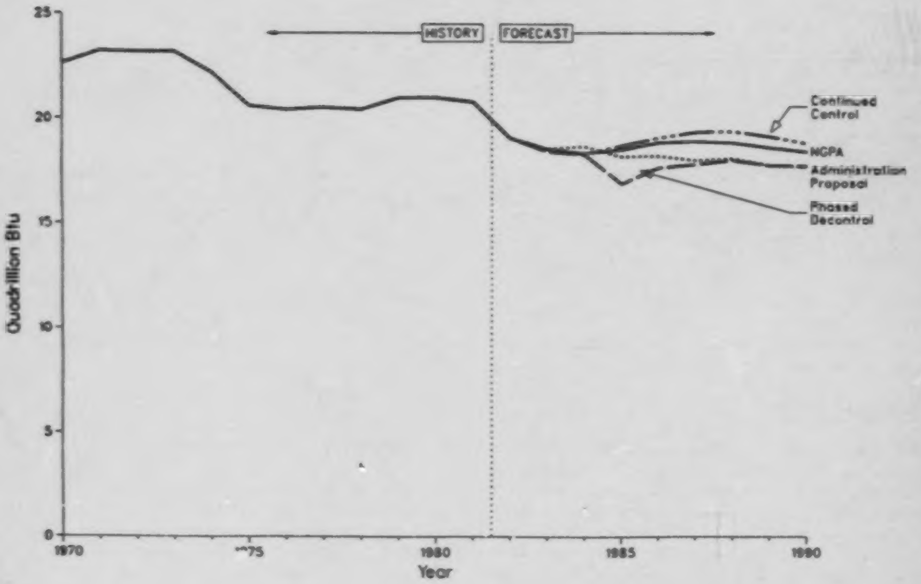
Consumption

As seen in Figure ES4, projected consumption of natural gas declines somewhat in response to the projected NGPA price path. As would be expected, the higher prices associated with phased decontrol reduce consumption below that of the NGPA case, while the lower prices under continued controls encourage more consumption. However, in the latter case, 0.4 Quad of "supplemental energy" is needed in 1990 to meet the demand. Thus the apparent higher consumption under continued controls may include curtailments, switching to alternate fuels, or increased imports. Under the Adminstration's proposal, consumption is lower due to conservation and additional fuel-switching.

Consumer Prices

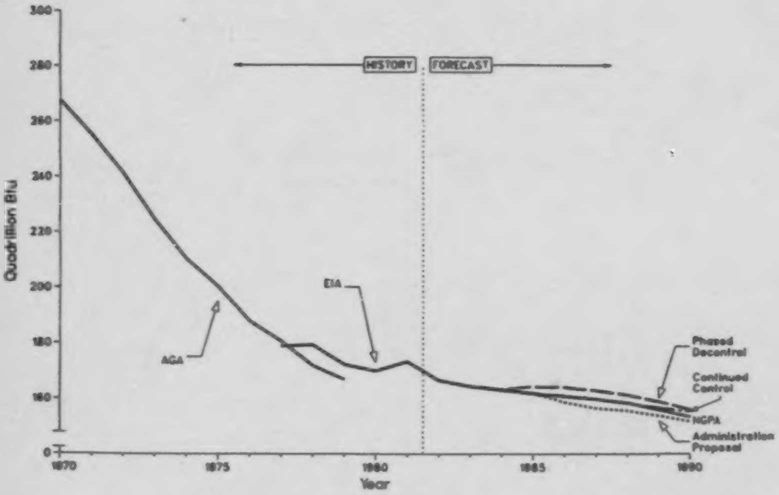
Under continued controls, average consumer prices are slightly lower than in any other case. But, as a consequence reserves are not replaced and the potential for shortages is increased. Under phased decontrol prices are generally higher than under the other cases (see Table ES2). Under the Administration proposal case, the consumer prices are slightly higher in 1985 and 1990 than under the NGPA, because there is no old gas cushion to roll in higher priced new gas.

Figure ES2. Natural Gas Production Under the NGPA and Alternative Policies



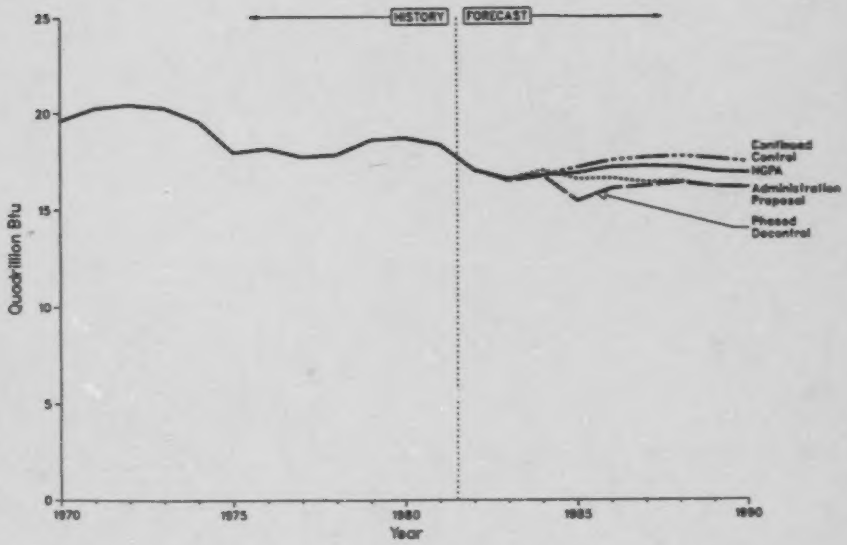
Source: Historical data, Annual Report to Congress 1981, Table 45, p. 103; forecast data, Gas Analysis Modeling System.

Figure ES3. Natural Gas Reserves (excluding Alaska) Under the NGPA and Alternative Policies



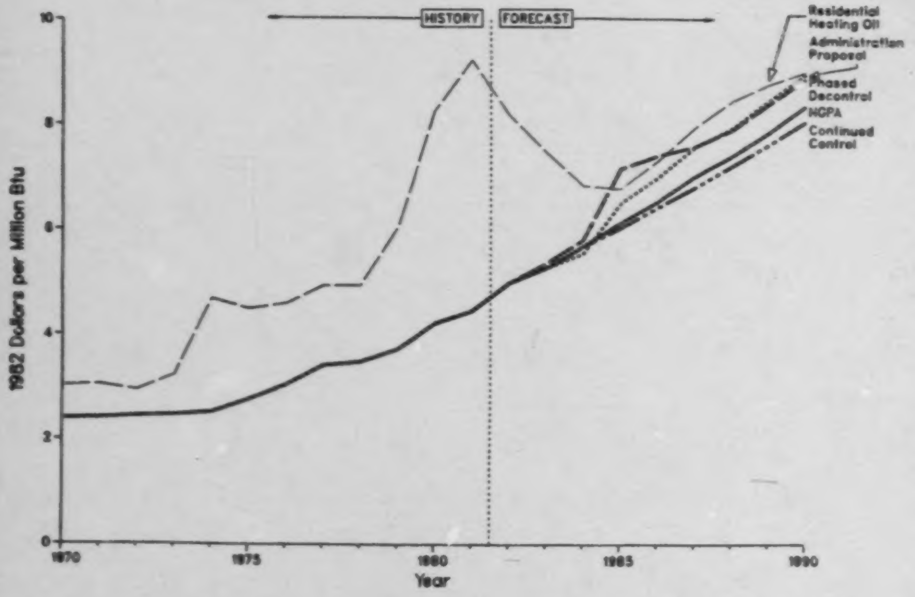
Source: Historical data, EIA: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1981 Annual Report, AGA: American Gas Association, American Petroleum Institute, and Canadian Petroleum Association (published jointly), Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada, reports for December 31, 1970-1979, Volumes 25-34. Total reserves are reduced by Alaskan reserves. Forecast data are from the Gas Analysis Modeling System.

Figure ES4. Total Consumption of Natural Gas Under the NGPA and Alternative Policies



Source: Historical data, Annual Report to Congress 1981, Table 47, p. 107; forecast data, Gas Analysis Modeling System.

Figure ES5. Average Price of Natural Gas Consumed by the Residential Sector Under the NGPA and Alternative Policies



Source: Historical data, Annual Report to Congress 1981, Table 52, p. 117; forecast data, Gas Analysis Modeling System.

Macroeconomic Impacts

The most obvious impact of the four cases on the economy occurs through differences in price. Thus economic growth is dampened by the higher prices under phased decontrol and accelerated by the lower prices under continued controls. However, this simple view ignores the impact of the large "supplemental sources" needed to meet demand under continued controls, and assumes that there is no adaptation of fiscal policy in response to the different levels of government revenues under the four cases. When these two adjustments are incorporated into the analysis, the economy under continued controls deteriorates after an initial improvement, while the initial dampening effect of phased decontrol is reversed by the late 1980's.

Conclusions

The alternative scenarios analyzed represent very different alternatives to an acknowledged problem, the natural gas market under the NGPA. Continued controls appear to postpone facing the problem until the 1990's. Phased decontrol is an uninviting solution in the short run, but by 1990 the market is in much better condition. The Administration proposal allows the market to adjust to events more quickly. Although average prices are higher after 1984 under the Administration proposal, by 1990 the new contract price is lower and the reserves to production (R/P) ratio is higher than under the NGPA.

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1. INTRODUCTION

Few topics affect the broad spectrum of American energy interests as does "natural gas deregulation." Federal regulation of the natural gas industry began with the passage of the Natural Gas Act of 1938 (NGA, Public Law 75-688). Over the succeeding 40 years, numerous laws and regulations, as well as their interpretations by the courts, have had a variety of effects on all aspects of the natural gas industry. The Natural Gas Policy Act of 1978 (NGPA, Public Law 95-621) is one of the most far-reaching of these laws.

This report presents the findings of an analysis of natural gas wellhead price deregulation, comparing the projected consequences of the current program of partial decontrol of prices under the NGPA with the proposal for complete decontrol advanced by the Administration, the continuance of the NGPA controls indefinitely, and an alternative to the NGPA identified in this report as "phased decontrol." Through this and other reports, the Energy Information Administration (EIA) seeks to provide both the public and private sectors with information describing the effects of current and alternative natural gas legislation.

Study Objectives

The NGPA was signed into law on November 9, 1978. The purpose of the Act was to facilitate the decontrol of natural gas prices in a manner which would not disrupt existing markets. In particular, Title I of the NGPA was to provide a price structure that would gradually escalate the wellhead price of certain natural gas production categories, classified as "new" gas, to parity with crude oil prices and thereby provide a smooth transition to the decontrol of new gas in 1985.[1] If there is a gap between crude oil prices and natural gas prices at the time of decontrol, a sudden large increase or "fly-up" of gas prices may result, due primarily to the existence of pricing clauses which tie the price of deregulated gas to the oil-equivalent value either directly or through the activation of "favored-nation" clauses. Because the authors of the NGPA assumed that the 1985 crude oil price would be about $15 per barrel, the pricing structure has not worked as envisioned, and a gap exists today.[2]

This report examines the possible consequences of the NGPA if price controls for several NGPA gas production categories are lifted as scheduled on either January 1, 1985, or July 1, 1987, and compares them with the impact of the Administration proposal, if it is enacted. The possible consequences of two other alternatives to the NGPA are also examined.

This report is based on a simulation of the natural gas market that takes into consideration: projected new discoveries; contract purchases of reserves; current natural gas contract pricing and take-or-pay provisions for production purchases; gas supplies currently dedicated to pipeline companies; cost-of-service pricing by pipeline companies and distributors; regional markets, with six-sector detail; and projected demand for each sector.

---

[1] Under the gradual price-decontrol structure of NGPA Title I, some gas remains under controls until its supply is exhausted. In addition, the incremental pricing provisions of Title II continue indefinitely.

[2] The January, 1983 refiner's cost for imported oil was $31 per barrel [4]. This is equivalent to about $22 in 1978 dollars.

Data Sources

Data for this report were obtained from many sources. Contract information was obtained from an EIA survey of about 400 producers and purchasers of natural gas, using Form EIA-758, "Natural Gas Producer/Pipeline Contract Report" [2]. Natural gas supply projections were generated by EIA's Production of Onshore Lower-48 Oil and Gas (PROLOG) Model [6], using data from EIA's annual reserves estimation report [5], The Current State of the Natural Gas Market [1], the American Petroleum Institute (API), Hughes Tool Company, and other sources. Offshore projections were obtained from EIA's Outer Continental Shelf (OCS) Model [7].

The Gas Analysis Modeling System (GAMS), which simulates the gas supply and demand markets and their interaction, and associated data used as the basis for this report will be described extensively in another report [8]. A summary of the overall methodology is provided in Appendix A, and a summary of the key assumptions is provided in Appendix B. In general, quantity and price data and market relationships were determined from the following sources:

- EIA-176, "Supply and Disposition of Natural Gas"
- EIA-758, "Natural Gas Producer/Pipeline Contract Report"
- FERC-2, "Annual Report of Natural Gas Companies"
- FERC-15, "Interstate Pipelines' Annual Report of Gas Supply"
- FERC-50, "Alternate Fuel Demand Due to Natural Gas Deficiencies"
- EIA-23, "Annual Survey of Domestic Oil and Gas Reserves"

Appendix C provides a comparison of the output of GAMS to historical data. The natural gas demand relationships for this analysis were derived using the same methodology used by the EIA in its 1982 Annual Energy Outlook (AEO) [9]. The macroeconomic impacts are based upon simulations performed on a macroeconomic model of the United States provided by Data Resources, Inc. Appendix D provides a side by side comparison of some of the major provisions of pending legislation.

Other EIA Studies

In August 1981, the EIA published a report entitled Analysis of Economic Effects of Accelerated Deregulation of Natural Gas Prices [10]. In May 1983, the EIA published its 1982 AEO which contained forecasts of energy futures [9]. The present report differs from the AEO in three major respects:

- It is based upon more current data, updated assumptions and it reflects the nature of existing natural gas contracts, pricing provisions, take-or-pay provisions, and deregulation provisions.

- It is based upon a detailed analytical model that was designed to provide the capability of assessing the flow of gas annually from producing regions through pipelines to distributors, in line with historic market patterns. This model was developed to permit an analysis of questions regarding regional impacts, prices in the interstate and intrastate markets, production, and the market impact(s) of long-term contracts.

- The concepts of market segmentation, market clearing, transmission, distribution and fuel-switching differ in the analytic implementation creating analytic results due to assumptions concerning natural gas market behavior.

The same basic assumptions concerning world oil price and economic growth are used in the AEO and this report. However, differences in approach to the analysis of behavior of national gas markets provide alternate views of what might happen to natural gas production, consumption and price. Differences are summarized in Appendix C, Tables C2 and C3.

Production and consumption differ by 3.3 Quads in 1985 and 2.2 Quads in 1990 between projections in this analysis and the AEO primarily in electric utilities. These differences are associated with corresponding differences in the prices of oil and gas.

Within this report, the NGPA and proposed alternatives are all compared using a consistent framework of assumptions and expected market behavior.

Some Remarks on Projections and Models

This report contains numerical projections. The probability that any projected numerical value will be realized is low, for several reasons:

- assumptions used in the model may never be realized;
- important data used with the models are subject to error; and
- model abstractions inherently contain oversimplifications.

Basic assumptions used as inputs to the models include projections of the world oil price and the Gross National Product (GNP) through 1990. These projections may never be realized, but they represent the current best judgment of the EIA and others.

To obtain numerical results, there must be numerical inputs. Data collection is itself subject to error. When important information on key aspects of the market being analyzed is not available, the input parameters must be estimated, and consequently, are subject to errors that will affect the projections.

Lastly, a model is, by definition, an abstraction of reality. For example, model boats and airplanes, and human models are abstractions from reality, and each captures some aspect of reality, although sometimes in a biased way. The model used in the development of this report is an abstraction, designed to capture important aspects of current and future natural gas markets. It may also be biased to the extent that it does not accurately represent the functioning of the markets at present.

In each of the three above-mentioned areas, the EIA has tried to be objective in making the many decisions necessary for this analysis. To serve the scientific process, appendixes are included to give the reader a better understanding of the overall modeling process. Complete documentation of the modeling process will be published separately.

With all of these assumptions and caveats, one might ask why an effort like this should be undertaken. There are several reasons:

- New and important insight may be gained from this type of modeling.
- The assumptions and data used in the analysis of policy options are made explicit and visible and are internally consistent.
- Competing alternatives can be compared within this consistent framework and their sensitivity to the assumptions used can be readily examined.
- The results can serve as a foundation for a reasoned qualitative debate.
- No better alternative has been found.

Although, in principle, a careful qualitative analysis of the gas market (or of any large system in fact) should identify all important assumptions and relationships, especially when the analysis is committed to paper, there is a natural tendency to discriminate with or without conscious bias against details that seem only marginally relevant to the main points of a study or that may produce unsatisfactory results. When a quantitative model is constructed, however, the need to account for the values of parameters and details of the formulations is evident, and significant details are not so easily overlooked.

An important function of a quantitative model is accounting, which is a demonstration of the internal consistency of both the data and the data relationships. That is, totals must be reconciled and accounts balanced. Often, in nonquantitative discussion, one has the feeling that additional supply, consumption, or conservation is being generated "ex machina." By the nature of the process, more care must be paid to making accounts balance in quantitative modeling. Any possible internal inconsistency is more or less transparently displayed by the model itself.

Quantitative models are potentially self-correcting. Counterintuitive numerical results ordinarily cause the analyst to reexamine the supporting data, the computational formulation, and the underlying theory and assumptions of the model. (Significant amounts of analytic judgment are introduced in this process, because the model outputs provide immediate trial criteria for assessing the match between our perceptions of reality and their consequences.) In contrast, there is no test of qualitative judgment except observation of reality much later, or opposing opinions of other people.

Moreover, it is difficult, particularly in forecasts, to determine net effects from purely qualitative considerations when there are many factors exerting "influence" or forces in many directions. A computerized model not only gives quick indications of such "results" but also permits experiments with alternative estimates of magnitudes of significant factors and, in general, examination of predicted effects of large numbers of scenarios or policy options to be examined.

Structure of the Report

Chapter 2 of this report discusses the NGPA, the Administration proposal, and other pending legislation regarding natural gas pricing and decontrol. Chapter 3 presents a discussion of the recent developments in the natural gas market. The description focuses primarily on significant changes in the market that are relevant to this report. Chapter 4 provides an analysis of the gas market under the NGPA as currently defined (the reference case) and presents a sensitivity analysis of the reference case. Both high and low supply and demand cases are reviewed to provide additional insight into the response character of the methodology. The analyses of the Administration proposal and other policy alternatives are discussed in Chapter 5. An analysis of macroeconomic and household impacts of the policy alternatives is presented in Chapter 6. A summary is presented in Chapter 7.

Appendixes A-D provide a summary of the overall methodology employed, a statement of key assumptions necessary to interpret the report findings, a comparison of projections in this report with those of other studies, and a comparison of pending legislation.

2. CURRENT LEGISLATION AND SELECTED PROPOSED LEGISLATION

This chapter summarizes the provisions of the NGPA, the Powerplant and Industrial Fuel Use Act (Public Law 95-620), and several alternative policy initiatives. The objective of the analysis is to assess the ramifications of major potential changes.

Natural Gas Policy Act of 1978[1]

Title I of the NGPA established a complex schedule of wellhead prices. The maximum price that producers can receive is based on the date a well was started, the depth of the well, its proximity to other wells, whether the gas was committed to the interstate market on or before November 8, 1978, the date the well began production, and the geology and geography of the deposit from which the gas was produced. When a well qualifies for more than one pricing category, the price ceiling is the highest applicable.

Figure 1 shows a simplified scheme of how ceiling prices for gas produced from new and old reserves change over time. With few exceptions, the initial price ceilings were set on April 20, 1977. Initial price ceilings are adjusted, as prescribed by the NGPA, by an inflation factor, and in some cases by an escalation factor. In addition to the ceiling prices, the purchase price may include State severance taxes and certain gathering and treating costs (Section 110).

Production from reserves can be divided into roughly three categories: old interstate, old intrastate, and new. Most old reserves (i.e., those existing prior to 1977) are produced under price ceilings governed by Sections 103, 104, 105, and 106. These price ceilings change through time depending on the NGPA Section, contract provisions, and depth of the well.

Natural gas dedicated to interstate commerce on or before November 9, 1978 (effective date of the NGPA), has as its maximum lawful price a "just and reasonable" rate as established by the Federal Energy Regulatory Commission (hereinafter referred to as the Commission), plus an inflation adjustment (Section 104(b)). The maximum lawful price of natural gas under intrastate contracts (Section 105(b)) (i.e., natural gas not dedicated to interstate commerce before November 9, 1978) is split into two categories based on its contract price on November 9, 1978. If the price was higher than the Section 102 ceiling price ($2.06 per million British thermal units (Btu)), the ceiling is the higher of the Section 102 ceiling price, or the then existing contract price, plus an inflation adjustment. If the contract price was lower than the Section 102 ceiling price, the ceiling is the lower of the price determined by the then existing contract terms and the Section 102 price.

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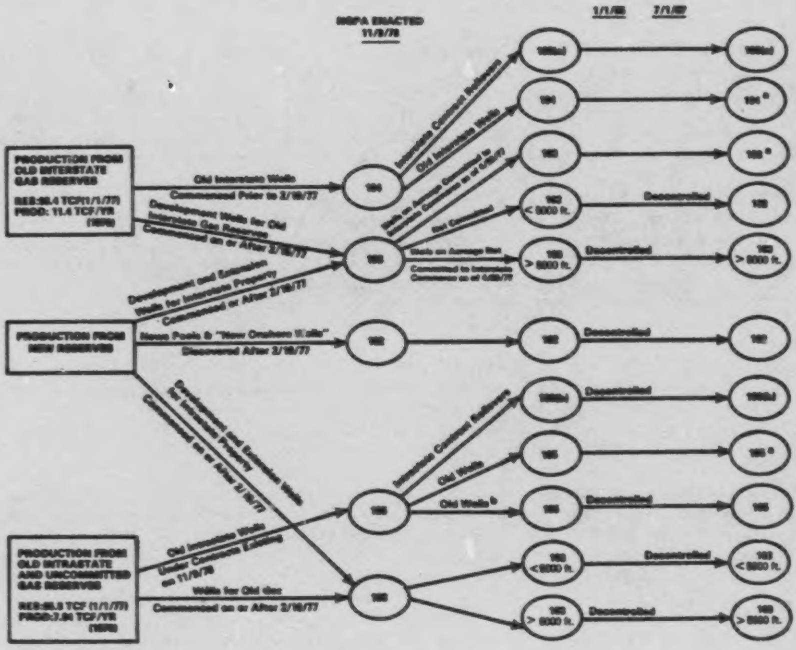
[1] See Reference 1 for a detailed discussion of natural gas reserves and production under the NGPA.

Figure 1. NGPA Title I Maximum Ceiling Price Categories for Onshore Lower-48 Natural Gas from Wells Less Than 15,000 Feet Deep


NGPA ENACTED 11/9/78
1/1/85
7/1/87
PRODUCTION FROM OLD INTERSTATE GAS RESERVES
RES:38.4 TCF(1/1/77)
PROD: 11.4 TCF/YR (1976)
Old Interstate Wells
Commenced Prior to 2/19/77
Development Wells for Old Interstate Gas Reserves
Commenced on or After 2/19/77
Development and Extension Wells for Interstate Property
Commenced or After 2/19/77
PRODUCTION FROM NEW RESERVES
New Pools & "New Onshore Wells"
Discovered After 2/19/77
Development and Extension Wells for Intrastate Property
Commenced on or After 2/19/77
PRODUCTION FROM OLD INTRASTATE AND UNCOMMITTED GAS RESERVES
RES:85.3 TCF (1/1/77)
PROD:7.84 TCF/YR (1976)
Old Intrastate Wells
Under Contracts Existing on 11/9/78
Wells for Old Gas
Commenced on or After 2/19/77
104
103
102
105
Interstate Contract Rollovers
Old Interstate Wells
Wells on Acreage Committed to Interstate Commerce as of 4/20/77
Not Committed
Wells on Acreage Not Committed to Interstate Commerce as of 4/20/77
Interstate Contract Rollovers
Old Wells
Old Wells b
106(a)
104
103
103 < 5000 ft.
103 > 5000 ft.
102
106(a)
105
105
103 < 5000 ft.
103 > 5000 ft.
Decontrolled
Decontrolled
Decontrolled
Decontrolled
Decontrolled
Decontrolled
Decontrolled
106(a)
104 a
103 a
103
103 > 5000 ft.
102
106(a)
105 a
105
103 < 5000 ft.
103 > 5000 ft.

[a] Not decontrolled.

[b] Priced higher than $1 per million Btu, under a definite escalator clause.

Note: Stripper wells and high-cost gas are not included.

Source: Reference 1

On November 1, 1979, high-cost natural gas produced from wells deeper than 15,000 feet drilled after February 19, 1977, and which was originally priced according to the Section 102 formula, was deregulated as prescribed by the NGPA. Gas produced from geopressured brine, coal seams, and Devonian shale was deregulated on the same date. New Section 107 categories were established for natural gas produced from tight formations and natural gas produced from qualified production enhancement methods. The ceiling price for tight formations was set at twice the price set under Section 103. The ceiling price for qualified production enhancement is the Section 109 ceiling price. Other categories are currently under consideration.

Interstate contracts that roll over (i.e., are renegotiated upon expiration) continue under the "just and reasonable" rate structure with a minimum ceiling of $0.54 per million Btu as of April 1977, plus an inflation adjustment, as defined in Section 101(a). Intrastate contracts that roll over continue at their previous price plus inflation with a minimum ceiling of $1 per million Btu as of April 1977, plus an inflation adjustment.

An additional difference between contracts that roll over for old gas (Sections 104 and 105) is the producer's ability to determine the purchaser. In the interstate market, permission must be obtained from the Commission to abandon an interstate purchaser. In the intrastate market, after a contract under Section 105 has expired, the producer is free to choose any purchaser, including interstate purchasers.

The conditions for lifting the price ceilings on January 1, 1985, are different for interstate and intrastate gas. Interstate gas under Section 104 or Section 106(a) is never decontrolled, but its price may be raised by the Commission under the "just and reasonable" conditions of the Natural Gas Act. Intrastate contracts that roll over before 1985 are decontrolled if the price on January 1, 1985, exceeds $1 (in 1985 dollars) per million Btu (Section 121(a)(3)). Intrastate contracts that do not roll over by 1985 are decontrolled if the price established by a definite escalator clause (or established under a contract with no escalator clause) exceeds $1 per million Btu on January 1, 1985 (Section 121).

Almost all development and extension wells begun after February 19, 1977, qualify for Section 103 price ceilings. With the exception of wells that were producing gas from acreage dedicated to interstate commerce before April 20, 1977, the price ceilings for Section 103 wells deeper than 5,000 feet are lifted on January 1, 1985. Ceilings for wells less than 5,000 feet are lifted on July 1, 1987 (Section 121(c)). Therefore, some reserves booked prior to 1977, but not fully developed by 1977, can be produced under Section 103 ceilings, and as early as 1985 a portion of their production will have no price ceiling.

In order to qualify for Section 102 status, an onshore well started after February 19, 1977, must produce from a new reservoir or be 2.5 miles from, or 1,000 feet deeper than a marker well (i.e., a well producing in commercial quantities any time between January 1, 1970, and April 20, 1977). Offshore gas qualifies for Section 102 if production is from new leases (Section 102(c)) or reservoirs "discovered" on or after July 17, 1976 (Section 102(d)). With the exception of gas priced under Section 102(d)), gas qualifying under Section 102 will have no price ceiling on January 1, 1985.

Powerplant and Industrial Fuel Use Act of 1978 (PIFUA)

The PIFUA is perhaps the second most important recent legislation affecting the demand for natural gas, particularly by electric utilities and large industrial users. PIFUA was designed to reduce petroleum and natural gas consumption by electric utilities and large industrial boilers, and to encourage greater use of coal and alternative fuels such as shale oil, uranium, renewable energy sources, by-products of industrial operations, and synthetic oil and gas.

The Act applies to all new electric powerplants and large industrial boilers. It prohibits such plants from consuming oil or natural gas as a primary fuel unless an exemption is granted. Permanent or temporary exemptions are granted if the cost of using coal or alternative fuels "substantially exceeds" the cost of consuming imported oil, or if environmental restrictions prevent the use of coal or an alternative fuel. Permanent exemptions also may be granted to peakload powerplants or facilities using a mixture of oil or gas and coal or alternative fuels. Cogeneration facilities that cannot use coal, facilities used only for emergency purposes, and certain other facilities also qualify for permanent exemptions.

Temporary exemptions are granted to plants that, by the end of the exemption period, will be retired; will switch to synthetic fuel; or will use an innovative technology for burning coal. The Secretary of Energy is also authorized to grant a temporary exemption to any powerplant when the exemption is in the public interest. Although temporary exemptions usually may not exceed 5 years, in some cases they may extend up to 10 years. Such temporary exemptions may be based upon either future use of synthetic fuels or lack of adequate coal or alternative fuel supplies.

The PIFUA also contained provisions designed to limit the use of natural gas in existing electric powerplants. Natural gas was to be prohibited as a primary energy source in existing electric powerplants after January 1990, unless the utility company submitted a plan for reducing its natural gas consumption by 1990 to 20 percent of its natural gas consumption in 1976. In any year prior to 1990, a powerplant was not to be permitted to consume a greater proportion of natural gas than its average in the period 1974 through 1976. The Budget Reconciliation Act of 1981 (Public Law 97-35) removed these restrictions on existing powerplants, but the restrictions on new powerplants remain in force.

Pending Natural Gas Legislation

The NGPA was designed to decontrol prices in a manner that would not disrupt the market. Under the phased-price decontrol structure of the NGPA, some gas always remains under controls until it is exhausted. In addition, the incremental pricing provisions of Title II are to continue indefinitely. Several of the apparent premises upon which the NGPA was developed have proved over time to be in error. There are currently numerous proposals for modifying the NGPA principally to address pricing issues but also problematic contracting practices. The following sections review several of these bills. Appendix D provides a side by side summary of the NGPA with four alternative policies.

Administration's Proposal

On February 28, 1983, the President announced that he was sending to Congress "a proposal for correcting problems that have resulted from excessive regulation of the natural gas market." Subsequently, the Administration's proposal, the "Natural Gas Consumer Regulatory Reform Amendments of 1983," was introduced in the Senate (S. 615) by Senator McClure (R-ID) and in the House (H.R. 1760) by Congressman Corcoran (R-IL). The fundamental thrust of the proposed legislation is to deregulate natural gas at the wellhead and ensure transportation of gas to markets. Additionally, incremental pricing and the gas provisions of the PIFUA are repealed. This deregulation process is not immediate and involves complicated transitional provisions.

This transition process, to be completed by January 1, 1986, allows time to effect the transition and in the interim period has several mechanisms designed to protect consumers from excessive price increases. The mechanisms limit the pass-through of interstate purchased gas costs, provide a cap for or freeze all gas prices at the wellhead, and require transportation of gas under contract carriage conditions.

Title I of the proposed legislation requires that until January 1, 1986, interstate pipelines not pass any costs above inflation through to consumers by means of the Purchased Gas Adjustment (PGA) mechanism (that is, an automatic adjustment process every 6 months). Any additional costs above inflation would be reviewed at a hearing to determine if the additional costs were "just, reasonable and prudently incurred." This determination requires, retrospectively, explicit consideration of "availability of lower cost supplies."

The cost of a pipeline's own gas or of its affiliates' gas cannot be passed through in some cases. If a pipeline has initiated a reduction in take-or-pay of lower price gas, the take-or-pay percentage for the pipeline's or its affiliates' gas must be reduced to levels of the less expensive gas.

Title I has caused considerable debate on the exact interpretation of the pass-through limitation. Since the proposed legislation requires a hearing for costs "incurred," this hearing must occur after the fact. This may constitute retroactive ratemaking, which is not current practice and generally considered to be a bad ratemaking procedure. If rates are set retroactively and increased costs are determined to be recoverable, the Commission must allow the companies to increase working capital and carrying costs, causing higher ultimate costs. It appears that, if costs incurred prior to the hearing cannot be passed on, either the pipeline company's stockholders must bear the costs or the company, after reaching its automatic pass-through limit, will start curtailing customers. In the first case, the U.S. Supreme Court in Smyth v. Ames required that regulators allow a fair return on equity for regulated companies.

Under Title II, renegotiated, new, or amended contracts are not subject to price controls or to "commitment status" under the Natural Gas Act (NGA). On January 1, 1986, all price ceilings are lifted. Gas production scheduled for decontrol in 1985 under the NGPA is subject to the gas cap price (if lower than the NGPA price ceiling) until January 1, 1985. All other categories not otherwise decontrolled are subject to the same provisions until January 1, 1986. High-cost gas is allowed the higher of the price on date of enactment and the gas cap price. Finally, standby controls and reports to Congress are eliminated.

Title III provides for the transition to decontrol in 1986 by specifying the price cap and its effect, reducing take-or-pay requirements to a maximum of 70 percent of deliverability, and granting "market-out" provisions. The gas cap price is a weighted average of the prices paid in the most recent 3 months of estimated deliveries under new and renegotiated contracts. The gas cap price is then used as an additional restriction on the ceiling prices of all but high-cost gas.

As an incentive to renegotiate or amend contracts, the bill grants either party to a contract the right to terminate that contract after 45 days' notice if it has not been amended or renegotiated by January 1, 1985. If a contract is terminated, the pipeline is obligated to transport the volumes which would have been delivered under the contract for $.05 per MMBtu plus cost. Any purchaser may reduce the take-or-pay, based on deliverability, to 70 percent of deliverability (this does not count as a renegotiation), but must transport the amount not taken, if asked, at cost plus $.05 per MMBtu.

An important consumer protection mechanism in the transition is the gas price cap. Several technical issues exist in the calculation of the gas cap price which may render it unrepresentative of a market price for gas. Renegotiations would take into account the current contract terms. For example, if the price were high, a gradual reduction downward may be the most acceptable to both parties. This might take place in such a way that the expected present value of the cash flow is the same as would be expected if the contract were renegotiated in 1985. In this case the price entered in the gas cap calculation may be much higher than the market price.

Moreover, if the price were low, the price may be gradually increased for the same reason as above, and the prices used in the gas cap price calculation would be lower than the "market price." High-cost gas is less than 5 percent of current purchases, while, for example, "old" (Section 104, 105, and 106) gas accounts for more than 50 percent of current purchases. It would be naive to assume that deviations would fortuitously balance out. Further, the gas cap price may fluctuate widely as the price renegotiation associated with a contract for large deliveries may overwhelm the other contracts used in the calculation for a given three month period.

Title I may inhibit the renegotiation of old interstate gas contracts. Currently, old gas is more than 50 percent of all purchases. It is expected that in 1985, old gas contracts will be renegotiated upward in price. With a pass-through limitation, the pipelines may claim "force majeure," stop buying gas, and initiate curtailments, or simply become contract carriers.

A more accurate measure of the "market price" is the new contract price, but because less than 10 percent of the market has historically been under new contracts in any given year, its price could become overwhelmed in any gas cap price calculation. For example, since currently about 50 percent of the old gas is below the average wellhead price, any renegotiation that moves the price up gradually could create a very low gas cap price.

Under Title IV, the principal focus is the elimination or relaxation of barriers to intermarket trading and explicit direction for the creation of contract carriage for pipelines. The definition of surplus gas, that is, amounts that can be sold off-system, has been relaxed to that which "exceeds current demands" and the Commission's jurisdiction is removed from certain interstate transactions. Intrastate pipelines are granted access to Outer Continental Shelf (OCS) gas.

Under the contract carriage authorization, if there is available capacity, the Commission can order an interstate pipeline to carry gas for cost plus $.05 per MMBtu. Significantly, none of this amount is credited to jurisdictional accounts; that is, it is all profit. This provision and Title I create a strong incentive for interstate pipelines to get out of the reserves ownership business and into transportation of gas.

An additional impediment to the renegotiation of old gas and, in general, all gas is that proceedings at the Commission for ordering carriage may take a considerable amount of time. Consequently, the producer may not be able to get the gas to the market. The producer may shut in the gas until authorization is granted, but may lose the leasehold if there is no production. To expedite this process, the pipeline could be required to demonstrate that there is no capacity available, or to carry the gas while waiting for an authorization from the Commission.

Title IV contains some problematic technical provisions that should be addressed. Currently, where the gas changes carriers several times, each carrier gets $.05 per MMBtu for transporting the gas in addition to cost. Further, actual transportation costs are more closely related to distance and volume than heat content. The incentive may be more appropriate on an Mcf-mile basis.

Representative Gephardt's Proposal

On March 18, 1983, Representative Gephardt (D-MO) and seventy-three co-sponsors introduced the "Natural Gas Consumer Relief Act" (H.R. 2154). The proposed legislation has three major thrusts: to relax contract terms and eliminate certain types of provisions; to require contract carriage under certain conditions; and to roll back price ceilings and extend decontrol dates.

Under Title I, for post-NGPA gas (Sections 102, 103, 107, and 108) a pipeline (not all purchasers) may reduce for 3 years its take-or-pay requirements to 50 percent of the maximum annual contract quantity. Since no provisions are made for gas not taken under the take-or-pay roll-back, it remains subject to the existing contract.

A pipeline may "market out" of a contract if it has not been renegotiated within 30 days of a request for renegotiation. Higher-priced contracts must be acted on first, with priority given to those with affiliated producers. Further, pipelines are given the right of first refusal, but no new contracts may be signed by a pipeline at higher prices than those involved in a "market-out" transaction. The only basis for discrimination among producers is price. Any gas involved in a "market out" transaction is freed of obligations on the part of the producer and must be transported under contract carriage conditions by the pipelines.

All indefinite escalator provisions tied to natural gas or other commodities are declared unenforceable. (In a strict interpretation of this Section, escalators tied to general inflation would be eliminated because all inflation indexes are tied to commodities.) This bill, however, does not explicitly disallow periodic renegotiation. Further, the bill requires that the purchase strategy of interstate pipelines be to minimize purchase costs for a guaranteed pass-through.

For all purchasers from interstate pipelines, minimum commodity bills in excess of payment for 50 percent of annual volume, or those without make-up provisions, are declared unenforceable. This provision does not disallow demand (fixed) charges.

Contract carrier authorization may be granted by the Commission for producers or purchases from producers if there is (1) available capacity, (2) no new construction required, and (3) no impairment of service to existing customers or future non-interruptible customers. This process has the same or greater potential time delays as the Administration's proposal. The consideration must be "just and reasonable" as defined by the NGA. Further, an intrastate pipeline company cannot become jurisdictional under the NGA by purchasing gas in this manner.

The proposed legislation also requires the Commission to undertake a rulemaking to issue standards for interstate pipeline tariffs to ensure they are sensitive to market signals in the end-use markets. Finally, all first sale contracts will be filed at the Commission.

Title II rolls back prices and extends NGPA decontrol dates for two years. The price adjustments are based on January 1982 and are adjusted monthly at the lower of 75 percent of the change in the GNP deflator or the change in the CPI energy index. Additionally, the price ceilings are to include all production-related costs.

This adjustment has some potential problems. For example, if in the mid-1980's the world oil price begins to rise and triggers general inflation, the price of natural gas will not be allowed to rise as rapidly, generating shortages or the need for additional imports. Further, with increasing wellhead prices of crude oil, drilling incentives will shift from gas to oil, thereby exacerbating the problem by lowering gas supplies.

High-cost gas and imports are capped at 150 percent of the Section 103 price ceiling, and no new categories of high-cost gas will be allowed. For old interstate gas (Sections 104 and 106) and Section 109 gas, price increases are limited to price adjustments as specified by the ceiling price; that is, the Commission is no longer allowed to adjust rates for those categories under "just and reasonable" rate provisions of the NGA. Ceiling prices are to include severance taxes and gathering costs. The Commission may, however, allow exceptions to price ceilings to provide the seller with a just and reasonable return.

In general, all changes that were to take place on January 1, 1985, and July 1, 1987, are deferred 2 years. This includes decontrol dates and increases in price ceilings.

Representative Addabbo's Proposal

On March 2, 1983, Representative Addabbo (D-NY) introduced a bill (H.R. 1752) and on March 3, 1983, Senator Heinz (R-PA) introduced the same bill (S. 689) entitled, "Natural Gas Policy Act Amendments of 1983" (H.R. 1752). In general, the bill reduces ceiling prices and take-or-pay requirements, voids most indefinite escalator clauses, caps the amount of revenue that can go to the pipelines' equity accounts, and grants market-outs for all first sale contracts.

Unless contracts specifically allow increases authorized by Congress, the prices are rolled back to the price on November 8, 1978. The price ceiling inflation adjustment is eliminated on the date of enactment, and severance tax and gathering costs are included in the price ceilings. Only price increases specified and known on the date of contract are allowed; that is, no unpredictable escalation is allowed. This provision would not allow renegotiation and therefore would create incentives for very short-term contracts. The Commission is empowered to grant the seller allowances for a just and reasonable return and to reduce the ceiling price based on other consideration provided by the purchaser, for example, the value of transportation of liquids. The value of consideration in excess of $.05 per MMBtu for gas transported is credited to the pipeline's jurisdictional (that is, regulated by the Commission) customers.

Except for "old" and "stripper" gas (Sections 104, 105, 106 and 108), both parties to the contracts are given market-outs with a right of first refusal by the purchaser and a requirement for transportation by the purchaser. The Commission resolves all contract disputes and any refunds are subject to interest at the prime rate plus 3 points. Finally, the Commission is required to do a comprehensive study of minimum bills, financing of pipelines, and price responsiveness.

Representative Slattery's Proposal

On April 12, 1983, Representative Slattery (D-KS) and Representative Coats (R-IN) introduced the "Natural Gas Policy Act Reform Amendments of 1983" (H.R. 2508). The proposed legislation has five general provisions: gas from certain wells is immediately freed from price ceilings; market-out authority is granted to certain contracts; take-or-pay provisions are rolled back; "most favored nation" clauses are outlawed; and certain provisions of the PIFUA are repealed.

Under Title II, favored nation provisions are outlawed and, along with obligations to pay for gas not eventually taken, are declared unenforceable. With the exception of warranty contracts, a one-time market-out is granted to either party during the year following enactment for gas to be deregulated on January 1, 1985, high-cost gas and certain OCS gas (Section 102(d)). The purchaser is given a right of first refusal, but if the offer is declined must transport the gas on a "best-efforts basis." The "best-efforts basis" is qualified by existing obligations which are subject to hearings and motions filed at the Commission. The rates charged are to be agreed to by the parties or determined by the Commission.

Take-or-pay provisions above 50 percent of deliverability are declared unenforceable for 3 years. Exceptions are granted for casinghead gas, stripper gas; and on a case-by-case basis, as determined by the Commission, to prevent drainage, reservoir damage, and "irreparable" financial injury.

Price ceilings are removed for gas contracts covered by market-out provisions that are renegotiated or amended. Further, price ceilings are removed for wells begun after enactment, under new contracts, and not committed to interstate commerce on April 20, 1977.

Incremental pricing and the gas use restrictions of the PIFUA are repealed in a manner similar to the Administration proposal. Finally, the U.S. Department of Energy must study gas imports and report to Congress, and the Commission must issue a new policy statement for market sensitive rate design principles.

Other Proposals

On April 7, 1983, Senator Kassebaum (R-KS) and 13 co-sponsors introduced the "Natural Gas Consumer Relief Act" (S. 996) which in principle is similar to Representative

Gephardt's proposal. Minor differences include a cap of 200 percent of the Section 103 ceiling price on Algerian imports and a base year price ceiling rollback to August 1982 instead of January 1982.

On April 12, 1983, the "Natural Gas Competition Act of 1983," was introduced by Senator Bradley (D-NJ) in the Senate (S. 1049) and Representative Ritter (R-PA) in the House of Representatives (H.R. 2499), designed primarily as a substitute for contract carrier authorizations. This proposal puts the burden of proof on the pipeline dealing with the issue of excess capacity (above that necessary to serve existing customers). That is, the pipeline must demonstrate that the capacity is not available. A $.05 per MMBtu compensation is granted to the pipelines, but the pipeline will lose this compensation to its customers if the Commission is forced to order it. The Commission may order construction of facilities if the costs are reimbursed. Further, any reduction in takes by an interstate pipeline is subject to the right of first refusal, with transfer right, by distribution companies served by that pipeline.

On April 12, 1983, Senator Hart (D-CO) introduced the "Natural Gas Market Reform Act" (S. 1049) which addresses only the issue of high-cost gas. The proposal allows a purchaser to reduce the price and/or the take-or-pay amount. If this happens the producer may terminate the contract for the quantity involved in the reduction. The pipeline is required to carry the gas at the now standard $.05 per MMBtu.

Discussion of Proposed Legislation

Perhaps the most significant impact of the various legislative proposals is on natural gas contracts. The Administration's proposal is based on the theory that a wellhead market free from Federal regulations will function in ways that will efficiently deliver gas to end-use customers. That is, after the transition period there will be no Federal restrictions (except management responsibility for Federal lands and waters) on natural gas contracts. Implicitly, the legislation assumes that current market conditions or similar ones will not reappear, because if unrestricted, the market will adjust long before the situation becomes serious.

The Gephardt bill permanently eliminates commodity-based price escalation but does not specifically rule out periodic renegotiations. Contracts calling for periodic renegotiation were more frequently found in intrastate pipeline contracts prior to the NGPA. Additionally, pipelines can apparently have price escalators tied to the bill's price adjustment which is commodity-based. The Addabbo bill eliminates all but definite price escalation. Without flexibility to adjust prices both up and down to reflect market conditions, contracts may become very short-term, creating financing problems for both producers and purchasers.

Decontrol dates also differ among proposals. The Addabbo bill does not change the dates for lifting of price ceilings, but by eliminating indefinite escalators and reducing take-or-pay, defuses the "fly-up" for old contracts, although not for new contracts. The Slattery bill removes the price ceilings on some gas immediately upon enactment, leaving most to the NGPA schedule. The Gephardt bill moves dates for lifting price ceilings back two years but continues restrictions on contract provisions indefinitely. The Administration's bill starts total decontrol upon enactment and completes it by January 1, 1986.

In almost all proposals there are incentives for increased contract carriage of gas by pipelines. If there were no authorization delays, transaction costs or general fear of engaging in different practices, the Administration's bill would likely make pipelines contract carriers, "marketing out" of old contracts and negotiating new contracts to carry the gas. At $0.05 per MMBtu, additional profits of about a billion dollars annually are potentially available to the pipelines under this option. Under the Bradley bill, the burden of proof for not carrying gas is on the pipeline with economic incentives to voluntarily carry the gas. Under the Gephardt bill, the Commission orders contract carriage, but pipelines have no guarantee of doing better since the compensation is determined by the Commission under the NGA. Delays in authorization for carriage could effectively eliminate attempts to match willing buyers and sellers.

Under the Slattery bill, the scope is more limited and requires more consideration at the Commission with the potential for long lags. In general, the Commission's authority increases under the Gephardt and Addabbo proposals and decreases under the Administration's proposal. The requirement of contract carriage creates incentives for the evolution of spot and futures markets for natural gas and direct sales to large industrial companies, electric utilities, and distributors.

Selected Policy Alternatives

The four scenarios identified in Table 1 are designed to cover the range of proposals offered in the debate on the deregulation of natural gas wellhead prices. They range from a relatively extreme position (indefinite extension of NGPA price controls on all gas production) through the Administration proposal, which permits decontrol immediately after enactment for new contracts, and upon renegotiation for existing contracts. Incremental pricing, while an essential part of the NGPA legislation, coupled with the new wellhead pricing specification (as discussed in Appendix B), in actual practice is not a relevant factor in analyzing NGPA alternatives and is not addressed in the GAMS model.

A summary of selected terms used in Table 1 follows:

- NGPA price paths and decontrol schedule: The NGPA specifies formulas for calculating the price for each category of gas and the date of decontrol for most of those categories. Gas in other categories remains subject to price ceilings indefinitely.

- Incremental pricing: Title II of the NGPA specifies a method of passing a more than proportional share of higher-priced gas costs to industrial consumers. Currently, only large industrial boiler facilities using interstate gas are subject to incremental pricing. The Commission rulemaking (Phase I), which implemented incremental pricing, also exempted small industrial boiler fuel facilities that did not exceed 300 Mcf per day during their month of peak use. Congress rejected a Commission proposal (Phase II) implementing the extension of incremental pricing. A recent court decision, however, has overturned this veto and ordered the Commission to proceed with the extension of incremental pricing. The Supreme Court is currently considering the constitutionality of the legislative veto. Because it is not yet known what the Commission's ultimate proposal will look like, nor, given the appeals process, when or if it will go into effect, only Phase I incremental pricing is assumed.

- PIFUA: In the Budget Reconciliation Act of 1981, those portions of the PIFUA dealing with existing utility powerplants were eliminated, whereas restrictions on industrial boilers were not affected.

- Deregulation clauses: Indefinite escalator clauses specify the price of gas sold by reference to prices that are determinable only at a future date. The two most common types are commodity-tied pricing clauses (where the price is tied to the price of some commodity, such as No. 2 fuel oil) and most-favored-nation clauses (which tie prices to the highest prices received by producers for gas of similar quality and quantity in the same general geographic area).

Table 1. Overview of Legislative and Policy Alternatives

NGPA Reference Case	NGPA price paths and decontrol schedule.
Administration Proposal Case	Ceiling price is the lower of the NGPA ceiling or "average" new free market price (gas cap) until deregulation on January 1, 1986. Section 107 deep gas (currently deregulated) is capped at the higher of the gas cap price or price in effect at time of enactment. Tight sands gas is capped at the maximum allowable price on the date of enactment. Price regulations are removed from any new contracts or renegotiated contracts. It is assumed that prior to 1985 contract renegotiation does not measurably affect the price and distribution of gas. On January 1, 1985, for any contract that has not been renegotiated, either party may exercise a "market-out" or abrogate the contract. Take-or-pay requirements limited to 70 percent of deliverability in contracts in existence at enactment and not renegotiated subsequent to enactment (applies through December 31, 1985). Incremental pricing (Title II) and the Fuel Use Act are repealed.
Phased Decontrol Case	Increases from NGPA price ceilings to 70 percent of refiner's acquisition cost of oil[1] for all gas by January 1, 1985. The price ceiling for Section 107 wells is 70 percent of refiner's acquisition cost of oil as of January 1, 1983. All price regulations are removed as of January 1, 1985.
Continued Controls Case	NGPA price paths; no decontrol in 1985 (i.e., repeal of Section 121). Gas continues to be priced by Title I formulas. Section 107 gas now free from controls remains free from controls.

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[1] For this study, the refiner's acquisition cost of oil and the world oil price are assumed to be the same.

These contracts are permitted to operate as written, according to the information developed in the EIA contracts survey [2] for contracts in existence as of 1980 Contracts written in 1981 or later receive the ceiling price until decontrol and then receive the current new contract price upon decontrol.

- Highest allowed regulated rate: In all cases, these contracts are assumed to receive the price in effect upon deregulation. The price is permitted to increase upon deregulation according to a calculated ceiling price as if under continued controls. In effect, in the phased decontrol case, the ceiling price becomes a fraction of 70 percent of the refiners' acquisition cost of crude oil until January 1, 1985, when it reaches the target price.

- NGPA price paths but no decontrol: Prices are calculated in accordance with the NGPA formula for each category. Some Section 107 gas remains decontrolled. All other types of gas, whether scheduled to be decontrolled under the NGPA or not, are allowed no more than the calculated price for that type of gas.

- NGPA Ceiling Changes: In each year the price is allowed to change by the amount that would bring it to the target price at the end of the period. This type of ramping scheme, which is found in several of the decontrol proposals, is far simpler than the geometric ramps contained in the original proposal put forward by Congressman Gramm [11]. The formula for the price (P) is as follows:

$$P_t = b_t + f_t(R_t - b_t),$$

where

P = the price for year t,

b = the NGPA ceiling price for year t,

f = the fraction of the increase that takes place in year t, and

R = the target price (e.g., 70 percent of the refiner's acquisition cost for crude oil) in year t.

- Seventy percent of refiner's acquisition cost: The price allowed is defined as 70 percent of the average cost of oil to American refineries (including shipping and insurance costs). This does not include any allowance for severance tax (worth about 5 percent). Various proposals have put the relationship between gas ceiling prices and oil prices at 60 to 80 percent of the refiner's acquisition cost. The 70 percent figure splits this range and appears to approximate the price of high-sulfur residual fuel oil, the competitive fuel in the industrial sector.

- Market-out: Allows parties to a contract to withdraw from a contract if either party finds the pricing terms to be uneconomical.

3. RECENT AND FUTURE NATURAL GAS MARKETS

The imposition of Federal regulations on the natural gas market has created segmented markets and interest groups. State regulations make every State market unique. Consequently, many different viewpoints exist. Under the NGPA in 1985, dramatic market changes take place. In this chapter, several viewpoints are presented and recent developments examined to help understand current and future natural gas markets and, unless otherwise stated, prices are expressed in nominal dollars.

At least since the early 1970's, when it became clear that Federal wellhead price controls were seriously affecting the gas market, there has been considerable debate over the pricing of natural gas. Some argue that gas should be treated similarly to water and priced at a "utility value," that is, the cost of production and delivery. This theory of natural gas pricing requires considerable regulation and assumes implicitly that natural gas is a basic necessity and not in scarce supply. Although natural gas markets could be characterized as constantly being in excess supply until the 1970's, that situation in general no longer holds, so that part of the basis for this theory is no longer valid. Because the process of determining the utility value is difficult if not impossible, the alternative consistent with this theory appears to be prespecified price ceilings as prescribed by the NGPA and the Gephardt and Addabbo proposals. This type of legislation has the potential for curtailments when the market wants more than prespecified prices allow.

Others have offered a "commodity value" theory, which states that gas should be priced at or higher than the heat or feedstock value of its competition. For example, gas serves essentially the same function as distillate fuel oil and electricity for home heating. In 1982, the average retail price of home heating oil was over $8 per MMBtu. Some argue that the price of home heating oil, plus a premium for the clean-burning nature of natural gas, should set the burner-tip price of natural gas. In some uses, natural gas competes with residual fuel oil and even coal. In 1982, the average price of residual fuel oil to electric utilities was below $5 per MMBtu. The difference between average home heating oil and residual fuel oil prices is over 50 percent of the "resid" price, making the "commodity value" of gas difficult to determine. Because this theory is probably the cause of some of the more problematic contract prices, its following appears to have dissipated. The Gephardt and Addabbo proposals both rule out commodity-based price escalation. The Administration's proposal leaves the issue to the market place.

Another school of thought holds that the market should determine the value of natural gas, which should vary with changes in supply and demand. The Administration's proposal is firmly rooted in this theory. However, most gas sells under long-term contracts that bear the history and scars of the past 20 years of natural gas market perturbations, so that the wellhead price of natural gas varies from below $0.30 per MMBtu to above $9 per MMBtu -- a 30-fold difference. When gas arrives at the burner-tip, in most cases the purchaser pays a price based on the seller's average purchase cost of the gas plus a charge for transmission and distribution. This practice and the nature of existing gas purchase contracts in downstream interstate natural gas markets raise the question of whether the wellhead and burner-tip markets communicate price signals in a manner that would permit timely market adjustments, and thus allow the market to function effectively in determining prices of natural gas.

The NGPA of 1978 was a compromise that evolved over 18 months of Congressional debate about, in particular, the pricing of natural gas. It was the first comprehensive natural gas legislation since the passage of the Natural Gas Act in 1938. The NGPA was intended to bring the intrastate market under Federal price ceilings at the wellhead, then to remove a large portion of both interstate and intrastate price ceilings (mostly on more recently discovered gas) in 1985. This has become known as "partial deregulation."

Beginning in the summer of 1982, the House Committee on Energy and Commerce, Subcommittee on Fossil and Synthetic Fuels, chaired by Congressman Philip Sharp and subsequently the Senate Energy and Natural Resources Committee, chaired by Senator McClure, held hearings to assess Federal policy on natural gas. Witnesses representing consumer groups, gas distributors, State public utility commissions, pipeline companies, and producers testified. With some notable exceptions, those who represented interests close to the burner-tip advocated gas price controls (or indicated a reluctance to remove them), weatherization programs, and income maintenance for the poor. Those who represented interests closer to the wellhead, in general, advocated fewer controls and freer markets.

Those representing the residential consumer were, in general, fearful of deregulation and advocated at least a slow, well-reasoned approach to change in the regulatory structure and support the Gephardt or a similar proposal. Industrial consumers, including the American Farm Bureau, which deplores interference in the energy market, tended to favor deregulation and in general support the "basic concept" of the Administration's proposal.

Distribution company representatives were worried about price signals being properly transmitted through the system and about the potential problem of indefinite escalator clauses. (The producers believe that private negotiations can solve the problem.) In this utility-regulated part of the industry, proposals were presented to transmit price signals, including common carrier status for pipelines, more price-flexible tariff provisions, and new regulations on take-or-pay and price escalators in wellhead gas contracts.

Representatives from Texas and Louisiana argued that the NGPA has created a gas market that favors the interstate system at the expense of the intrastate system. Old gas in the intrastate system was left "exposed" to price escalation by the NGPA, and consequently the intrastate "cushion" is small and unevenly divided. In general, intrastate pipelines support the Administration's proposal.

Representatives of the interstate pipelines stated that the NGPA, in general, has allowed them to buy more gas and is working well, but that they are concerned about some clauses in their gas purchase contracts written over the past 15 years, namely, high take-or-pay and pricing clauses that are potentially above market-clearing rates. The only way to remedy these problems, in their opinion, is through legislation.

Interstate pipelines generally, since the 1930's, have been opposed to the contract carriage, want take-or-pay legislatively reduced to 50 percent, but are willing to decontrol all "new-new" gas, that is, new after a recent date. Further, they would like market-out clauses for their high-cost gas.

With the exception of those controlling proportionally large amounts of deep gas production, producers wanted a quick transition to a free market, usually interpreted as the removal of Federal wellhead price ceilings. However, some independent producers have opposed the method proposed by the Administration. Additionally, there was virtually no support for a "windfall profit tax" on gas. This is not surprising, since the beneficiaries of such a tax would be outside the industry.

Exploration and Development

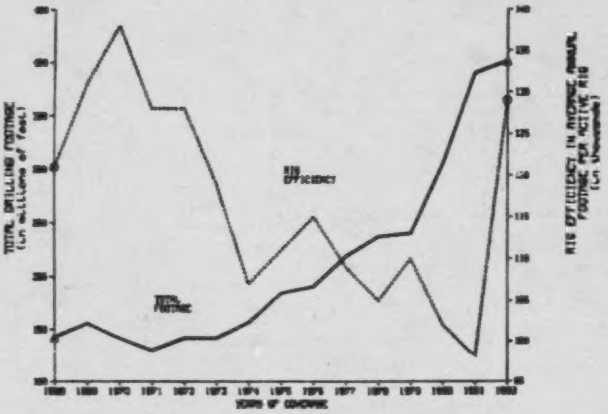
Before the 1960's, the wellhead market for natural gas could best be described as a by-product of the search for oil. When gas was discovered it was occasionally a disappointment, especially when there was no transportation system in the area. Even State regulations could not prevent the flaring of gas to produce associated liquids [15]. More recently, the increasing price of new gas has made it attractive to actually search for gas as a separate target.

Currently, the drilling market is "soft." Price increases have stimulated additional supply, mostly in the form of production capacity, and consumers have conserved and reduced purchases as a result of generally poor economic conditions. Currently, the market cannot adjust to the new conditions of over-supply in a timely fashion. This excess supply condition can be seen by the recent decline in seismic exploration crews and rotary rigs in operation [4]. Through 1981 and 1982, trade journals were reporting day-rate contracts of 2 years or more for rigs, but the day rates have given way to footage rates--a sign of stiff competition among rig operators [60].

The availability of rigs does not appear to constrain the wellhead market. The impact of the decline in rig utilization on drilling is not severe, because the efficiency of rigs (measured in footage completed per active rig) usually improves when the active rig count declines or grows at less than 15 percent, and the efficiency decreases when the growth is greater than 15 percent (see Figure 2). This decrease in efficiency is probably caused by the introduction of older, less efficient rigs and less experienced rig crews utilized in periods of high active rig growth.

The reasons for the "soft" wellhead market are at least threefold: a decline in drilling fund subscriptions, excess gas production capacity, and a perception of declining future wellhead prices. Drilling fund subscriptions were down over 50 percent in 1982 from 1981 [38], principally due to recent marginal tax rate changes, new tax shelter opportunities for investors (for example, individual retirement accounts), and reduced expectations. These funds are estimated to account for between 10 and 25 percent of drilling expenditures.

Figure 2. Exploratory and Developmental Natural Gas Well Footage Completed and Rig Efficiency (Footage Completed per Active Rig), 1968-1982



Source: API well ticket data (total United States, including Alaska and offshore) and Hughes Tool Co.

The recent decline in both oil and deep-gas wellhead prices and reduced purchases has caused cash flow problems for many producers who overextended themselves, and a reduction in available financial capital for further drilling. In addition, lending institutions, many of them burdened with a high percentage of "problem" loans in oil and gas, have sharply curtailed further lending and have tightened up lending procedures. These include many banks in the producing states historically active in oil and gas.

The Wellhead Market

Wide swings in new contract prices occur in part because only 5 to 10 percent of the gas wellhead market each year falls under new contracts, and an even smaller fraction is decontrolled. Since contracts for most of the gas currently flowing are long-term, that is, 15 years or more, a serious question arises concerning the ability of contracting parties to agree on pricing provisions over the long term. Recent contracts for decontrolled deep gas (gas from wells deeper than 15,000 feet) provide some indication of the trends in the market.

In early 1981, some new deep gas contracts were receiving wellhead prices greater than $9 per MMBtu, with contract terms that only allowed the price to increase. From late 1981 through early 1983, a turnaround appears to have taken place. At least 16 pipeline companies exercised "market-out" clauses (that is, contract clauses that allowed the pipeline to reduce the price it was paying for gas with the possibility of losing the reserves under contract) for some of their high-cost gas. Recently, several pipelines have exercised market-outs for the second time at the Section 102 price ($3.35 per MMBtu). At the same time, the price of deep gas under new contracts has been falling considerably below the earlier $9 price to between $5 and $6 per MMBtu, with contract terms more favorable to the purchaser, most importantly market-out provisions.

Take-or-pay clauses became a serious problem in 1982. Prepayments for gas not taken were near a billion dollars. Recently, the Columbia Gas and Consolidated Gas Companies have invoked the "force majeure" clauses in their contracts with suppliers to suspend take-or-pay payments. A "force majeure" clause in a contract excuses one of the parties from performance if unforeseeable events beyond the control of the party renders performance impossible or substantially more difficult. Force majeure is usually understood to refer to events such as strikes or wars. The pipelines contended that the unusually warm winter weather and prolonged economic recession constituted unanticipated events beyond their control which have reduced demand for their gas. This is a somewhat unusual application of force majeure since the purpose of a long-term commodity contract is to protect against fluctuations in supply and demand. However, the pipelines may be able to obtain concessions from suppliers anxious to avoid litigation. Since the prepayments must be entered into the rate base, this could cause a serious cash flow problem for pipelines and potential for bankruptcy.

The market for natural gas at the wellhead is in many ways similar to the long-term bond market. Any large company that acquires long-term debt on a regular basis has a portfolio of loans at various interest rates. The older loans have a lower interest rate, that is, a lower price, and current loans have higher rates. The trend for recent loans has been toward shorter loan maturity and variable interest rates, that is, indefinite prices. Also, shorter-term debt has increased in proportion to other debt. In many cases, long-term debt acquired by gas transmission and distribution companies carries the lender's requirement for maintenance of a minimum reserve margin. Creditworthiness is often determined on the weighted cost of debt.

The natural gas market is characterized by high incremental costs and low variable operating costs. For example, a field usually requires exploratory wells and dry holes before gas is discovered. Once gas is found, development wells must be drilled, but once a well is drilled, the production costs to keep the well flowing are small by comparison. To transport gas, pipelines and compressors must be installed, but after installation the variable cost of transmission is small. Further, once installed, equipment has a low value for resale or salvage. The high incremental or fixed costs and low resale value create opportunities for exploitation, since the proper economic decisions are based on marginal costs. The response to this potential opportunism in both interstate and intrastate markets has been long-term contracts.

Long-term contracts expose both parties to considerable risk due to an uncertain future. The producer (at the risk of oversimplifying) desires to get the highest possible price for gas. The most popular current mechanism used to achieve this purpose is a most-favored-nation clause that allows the producer to receive a price based on the highest prices in a defined geographic area. Most-favored-nation and other types of indefinite escalator clauses are not a recent addition to the natural gas market. The 1954 Supreme Court decision was in part a response to the problem of indefinite escalator clauses [61]. The existence of these clauses has again become a problematic issue in the deregulation debate and several proposals outlaw certain types of indefinite escalator clauses.

The producer wants a high cash flow and therefore must sell as much gas as possible. Take-or-pay provisions represent the current form of a guarantee for high cash flow. Take-or-pay at a minimum price is often argued as a method to ensure cost recovery. In recent markets these terms were more a reflection of supply, demand, and regulations than cost recovery. Further, if the reservoir from which the gas is produced has more than one operator, any reduction in take by the purchaser may mean that the gas is lost forever to drainage by another operator under the law of capture. This situation creates the perverse and inefficient incentive to produce and store gas simply to prevent drainage losses to other operators. This problem is alleviated if the reservoir is operated by a single producer, that is, unitized. While the producer desires high take-or-pay provisions for a high cash flow, he may be willing to undertake a partial "storage" function if properly compensated.

On the other side of the contract, the pipeline purchaser generally wants a low price and needs to be able to adjust to short-term (less than 2 years) changes in its market, such as a surge in demand caused by a cold winter or an unexpected drop in demand caused by a depressed economy. At the same time, in order to finance its operations, the pipeline often must demonstrate to bankers that there are sufficient reserves dedicated to its needs to justify long-term debt. Without firm supplies, a pipeline's risk increases, which may raise its cost of capital. Consequently, the purchaser attempts to acquire reserves but at the same time desires provisions for short-term adjustments that are currently available in the form of take-or-pay provisions. The smaller the take-or-pay percentage, the more flexibility the purchaser has to manage short-term adjustments and purchase a lower-cost mix of gas.

Take-or-pay clauses with makeup delivery provisions for gas paid for but not taken can be viewed as serving a storage function for the purchaser and, consequently, should be evaluated as an alternative to other storage options. To the extent that excess capacity exists in the transportation system by which gas can be moved quickly through the system, it is more efficient to use the original reservoir as the first choice for storage.

Beyond the short-term, the escalating price of gas at the wellhead may become too high for the current purchaser to market. Therefore, the purchaser needs to be able to withdraw from the contract if the gas cannot be marketed. Currently, this provision is known as a market-out provision. How or if this type of contract may work in the forthcoming deregulated market is not known.

In a deregulated wellhead market, the desire for long-term contracts is still present, but the volatility of indefinite price escalators puts the pipeline purchaser at the risk of being unable to market the gas under contract. If the pipeline purchaser owns the gathering system, it is possible for monopsony power (that is, one buyer, many sellers) to be exercised over the producers. One way of dealing with the problem of monopsony power of the purchaser is to require the purchaser, if he exercises a market-out provision, to supply transportation up to the original contract maximum at the cost of service. Further, if a market-out provision is exercised and the producer rejects a new price offer by the purchaser, as a matter of good faith, the purchaser could be given the right of first refusal on any new contract with price terms lower than the original contract.

Due to the higher risks of a deregulated market, the potential exists for other changes in the market structure. If the producer insists on indefinite escalator terms as described above, and if capital-intensive outlays are required for the delivery system, the opportunity for risk-sharing creates incentives for vertical integration of the producer and the purchaser. This integration would occur because, in a market with rising wellhead prices, the economic rent that accrues as a result of higher prices to producers, and losses that may occur due to marketability problems for the purchaser, are simply internal bookkeeping operations in the integrated firm. For a nonintegrated purchaser these conditions could cause substantial problems. In a market with falling wellhead prices, rent accrual is simply reversed unless the regulatory structure forces the rent to be passed through to the consumer. In the interstate market, vertical integration between purchaser and end-user is discouraged by FERC regulations, because there is no strong incentive for an interstate pipeline to perform a simple transport function.

Vertical integration is more common in the intrastate market, which previously was not subject to Federal regulation. In recent years, however, interstate pipeline companies have moved toward additional vertical integration at the wellhead, which can also take place in the form of joint ventures. This trend, which could be accelerated under a more deregulated market, may raise antitrust issues.

The institution of a spot market and a futures market for natural gas may assist the short-term adjustment process. The implementation of futures markets must still overcome several technical difficulties. Currently, off-system purchases are a form of spot market. Before the NGPA, intrastate gas was being sold under short-term contracts to the interstate market; currently, the situation is reversed. In the current situation, off-system purchases encounter opposition, because interstate customers believe that their "cushion" of cheap old gas is being dissipated in the intrastate market and because the intrastate pipelines consider this practice predatory competition. Neither group supports this type of arrangement. On the other hand, because intrastate customers are buying gas that they need and interstate pipeline companies are finding markets for their excess supply, both support the system, at least for the present. (For a more detailed discussion of this issue, see [56].)

With the greater availability of short-term sales and possibly a futures market, a gas purchaser could establish a gas purchase portfolio similar to a company's debt structure. Contracts that are long-term with high take-or-pay (for example, casinghead gas) would not necessarily command a premium price. Non-associated gas with flexible delivery provisions and large reserve backing may command a higher price. Futures markets allow for hedging and a guaranteed cash flow for the producer. Short-term sales would reflect current market conditions and could be above or below the gas price under other contracts.

The institution of a spot market for gas may be aided by the vertical integration of producer and purchaser. When significant amounts of gas are under long-term contracts, short-term or spot-market sales from a reservoir are viewed with suspicion and distrust by the long-term purchaser. In an integrated company, spot-market sales outside the company are an internal decision that, in principle, is less subject to "cheating" between the producer and the purchaser.

For many reasons, including inertia of company management, the long-term market strategies for natural gas often preempt the short-term market. Bidding for natural gas reserves requires an assessment of long-term demands of the purchaser's customers. Without additional flexibility, the "captive" customers in the natural gas market, particularly residential customers, may be forced to pay for the overestimates of demand to acquire more gas than will eventually be needed, and the industrial customer will bear the consequences of underestimation of future needs through curtailments.

Gas Storage

Gas storage, outside the reservoir of origin, is expensive. The economic rationale for gas storage is that existence of storage near the consumption point lowers the overall delivered cost of gas. That is, the combination of smaller capacity pipelines and storage near the end-use consumption point minimizes costs. Gas not demanded for consumption during off-peak months is injected into storage; it is later withdrawn to help meet peak demand, typically during the winter months. However, when excess capacity is present in an existing pipeline system, the opportunity exists for using the reservoir of origin as a "storage" reservoir.

Since the excess capacity of the pipeline could be used to help satisfy peak demand, the original reservoir could serve as a storage reservoir, but several problems arise. The two principal impediments to this system are the law of capture and the regulatory treatment of these costs.

If there are two or more operators in a reservoir, the law of capture allows gas under one operator's property to be produced and sold from the other's wells. To avoid this problem both operators attempt to produce gas as quickly as possible. Under this strategy, producing at less than the highest possible rate means loss of revenues and makes the storage option impractical. State regulatory bodies oversee the operation of this aspect of the market (with the exception of the Federal offshore).

Current gas rate accounting procedures require that the payment for gas not taken be capitalized and placed in the rate base. But if the gas is removed and placed in storage it is a current expense that is passed through via the PGA mechanism. This accounting requirement may cause myopic decisions on the part of the pipeline system, unnecessarily raising the cost of gas to the final consumer.

The Interstate Market

Transitions in the downstream natural gas market occur slowly because most gas is purchased by pipelines from producers under long-term contracts. Moreover, interstate pipeline companies are operated under a system of regulations and rate design based on the 1954 Phillips decision of the Supreme Court requiring wellhead price regulation. Because the NGPA moves the wellhead market away from regulation, downstream regulations need to be modified to conform to the NGPA. Spot market purchases are small and complicated by regulations hindering short-term market flexibility. Further, there are vast differences in price, quantity, and terms of current long-term contracts. The transitions affect different regions and users in radically different ways. In the interstate market, there are also major differences among pipeline companies in old gas endowments [3].

Over the past decade, wellhead purchase expenses have become the focus of attention for pipeline companies, but, due to fuel cost adjustment allowances in tariffs, costs have been passed on without detailed examination. In the interstate market, the cost of gas purchased by pipeline companies rose from about half of their operating revenues in 1971 to about 80 percent in 1981 [39]. (This situation is probably even more pronounced in the intrastate market, because the gas is transported over shorter distances, with lower transportation costs.)

During the past several years, wellhead purchase strategy has become important. At any point in time, the decision flexibility of the purchaser (i.e., the pipeline) confronted with many contracts with different take-or-pay and pricing clauses can be represented by the shaded portion in Figure 3. Point A represents the take-or-pay minimum purchase quantity (that is, the smallest quantity where taking and paying are coincident) for all of the purchaser's existing contracts. Point B is the maximum contract quantity of these contracts. (Point B may be either above or below A horizontally.) Depending on the pricing provisions of existing contracts and the company's longer-term strategy, it may be in the interest of the company to operate in the upper part of the shaded area and save its low-priced gas for the future. Further, the optimal strategy for the pipeline company may be to operate on the upper edge in the winter and the lower edge in the summer.

In the summer, most interstate companies purchase gas and store it for the winter peak. If there is a choice, lower-priced gas should be purchased and placed in storage, thus incurring low carrying charges and delaying cash outlays for higher-priced gas. In the winter, when demand is relatively inelastic, purchased gas costs are passed on almost immediately to the pipelines' customers. Consequently, purchasing high-cost gas in the winter and low-cost gas in the summer enhances the cash flow of the pipeline operators. In addition, because the summer load is usually more price elastic, the purchase of lower-priced gas for summer load allows pipelines to maximize total volume sold during the year, providing pipeline companies with higher total revenues.

Since the Natural Gas Act of 1938, the infrastructure of the interstate market has been carefully built on concepts of utility regulation. For example, prices in gas sales agreements between interstate pipeline companies are generally left unspecified, since they were controlled by the Commission prior to the NGPA. Downstream contracts

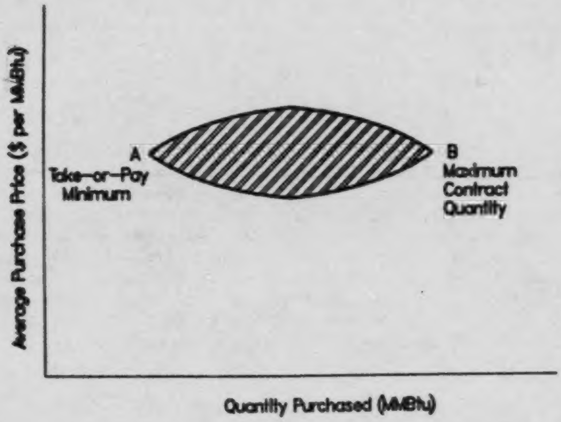

Average Purchase Price ($ per MMBtu)
A
Take-or-Pay
Minimum
B
Maximum
Contract
Quantity
Quantity Purchased (MMBtu)

Figure 3. Short-Term Decision Flexibility of Gas Purchasers

between pipelines and distributors and other pipelines contain demand charges and take-or-pay provisions often referred to as minimum bills. With the recent significant drop in demand and the potential for an even greater decline, the minimum bill has became a larger portion of costs, driving up average costs. The impact of minimum bill provisions on the distributor is similar to the take-or-pay impact in a pipeline wellhead contract. Under its current implementation, the NGPA, along with the pass-through mechanism of purchase gas adjustments, has allowed interstate pipeline companies considerable flexibility in the purchase price of gas that is simply "passed on" to the next purchaser.

In addition, there may be insufficient reserve backing for reported commitments of some interstate companies. For example, if the current commitments of United Gas Pipeline (as described by Form FERC-15 submissions of other pipeline companies) are to be met in the future, a very aggressive campaign to acquire low-priced reserves will be needed. These issues may become more difficult to address as the market moves toward greater decontrol at the wellhead and the Commission loses more of its authority to regulate gas purchases. In other words, how will pipeline and distributor regulations predicated on wellhead controls work in the absence of wellhead controls?

After almost 25 years of wellhead price ceilings, the behavior of interstate transmission companies in purchasing deregulated gas during the past 3 years is interesting to observe. Before the NGPA, the price paid for gas was under the tight control of the Commission, and interstate companies directed their attention to acquiring gas and assuring service to those who wanted it. When some gas was deregulated under the NGPA, a few interstate pipeline companies badly in need of gas signed contracts that, in retrospect, were not well conceived [2]. Fortunately, only a small portion of the market has been affected to date. The current trend in contracting is toward more favorable terms for the purchaser: NGPA price ceilings with market-out provisions. However, the current wellhead market is soft, and the situation could change quickly if demand increases.

The need for adjustments in the structure of downstream gas markets has been recognized. In a speech before the Federal Energy Bar Association in January 1981, Congressman John Dingell (D-MI), Chairman of the House Committee on Energy and Commerce, recognizing this need, cited nine possible "market-ordering" devices. They included "market-outs" for distributors and common carrier status for pipelines.

Interstate pipeline companies claim that they have been required by the Government to "balance supply and demand" [62]. Because the provisions for common carriage do not exist and the incentives for contract carriage of gas are small, there is little choice but for interstate companies to act as the "purchasing agent" for the distributors it serves. Although the task of balancing supply and demand is difficult, if not impossible, the interstate pipeline companies have long opposed common carrier status [61]. This opposition predates the Natural Gas Act (NGA) of 1938 and probably had considerable impact on the specifics of the NGA.

Distribution companies that are part of the interstate system have become more active recently. In California, Pacific Gas and Electric has asked its principal interstate supplier, El Paso Natural Gas, to exercise its "market-out" provisions for high-cost gas [40]. Southern California Gas Company, the Nation's largest gas distributor, has proposed a tariff with a "market test" for high-priced gas and a firm contract for lower-priced gas. Currently, all gas has the same average price, with penalties for taking less than a specified minimum amount. El Paso, an interstate pipeline serving California, claims that contracts for expensive imported gas should be the concern of the California gas utilities, and not simply that of the interstate pipeline serving them.

Last winter, Baltimore Gas and Electric Company sponsored television and newspaper advertisements informing its customers that their gas bills would increase by more than 30 percent and that the company could do nothing about it. Because distribution companies relying on the interstate market have no price negotiation power, the only remedies available to them are appeals to the Commission (which recently have brought no relief) and through other political channels. The Commission claims that the NGPA has seriously changed its authority in the matter of wellhead pricing and, therefore, that only Congress can rectify the problem. The inability of distributors to renegotiate the terms of their current agreements has created situations in which the distributors have appealed to the public and, at least by implication, the political process for relief.

An approach that could address the needs of some distributors and direct purchasers who want to become more active in their purchase gas decisions, and producers who want markets for shut-in gas production capability, is increased use of contract carriage. Since contract carriage of gas currently exists as an option, the Commission (FERC) needs only to create the incentives or, if necessary, order its use. The use of contract carriage as a market-ordering device is potentially very useful when pipeline systems are not operating at capacity or only small incremental costs are required to increase capacity. This mechanism, when properly implemented, relieves both potential monopoly and monopsony power of the interstate pipelines. On the other hand, common or contract carrier status for pipelines and distributors releases captive industrial and electric utility customers to make independent contracts with producers.

Some analysts have asserted that the interstate burner-tip market is "workably competitive." This assertion usually is based on two arguments: that most of the interstate market is served by more than one interstate pipeline, and that natural gas competes on the margin with fuel oil in the industrial market. The second argument assumes that the cost to "captive" customers will be controlled by industrial customers. Because a significant portion of a distributor's costs are both fixed and joint (that is, shared by more than one product), there is considerable flexibility in pricing to the various customer classes. Since the distributor hardly ever competes against other gas sellers, and interstate pipelines seldom compete against more than one other pipeline, the only serious competition is from alternative fuels. For various reasons the price of alternative fuels could rise considerably above the cost of gas, allowing for opportunism in the pricing of gas.

Recently, tariffs have been proposed that would price gas to industrial customers with the potential of switching to fuel oil in a way that would make it attractive to continue burning gas. Further, the price of fuel oil may rise for reasons unrelated to the gas market, such as an increase in the crude oil price or the use of additional cracking capacity to convert No. 6 fuel oil to transportation fuels, making less No. 6 fuel oil available. On the other side, lower crude oil prices and heavier crude oil may glut the No. 6 fuel oil market and cause many industrial users to switch from gas to oil. The way signals are sent to a deregulated wellhead market from the downstream market has received less attention than the issue of wellhead deregulation.

Intrastate Markets

Intrastate markets have experienced a different past and face a future somewhat different from interstate markets. For at least 10 years before the NGPA, the wellhead price for new gas in the intrastate market was above the ceiling prices allowed in the interstate market. Consequently, intrastate purchasers had virtually no competition from interstate pipeline companies in contracting for new onshore reserves. This is evidenced by the fact that the net reserve additions in the interstate Lower-48 onshore market were negative from 1968 to 1978 [24].

Each intrastate market is unique, having its own set of rules. In Texas, the Railroad Commission is the most influential regulatory body, with responsibility for both producer and transmission regulations. Louisiana, by contrast, has less regulation. Three States, New Mexico, Oklahoma, and Kansas, have passed statutes restricting the price of intrastate gas sales [58]. For example, in May 1979, the Kansas legislature enacted a statute restricting the operation of indefinite price escalator clauses. The Kansas Natural Gas Price Protection Act[1] provides that the price paid for natural gas in Kansas shall not be taken into account when applying an indefinite price escalator clause contained in contracts for intrastate gas entered into before April 20, 1977. The Act allows voluntary price renegotiation between the parties to the contract, and does not apply to contracts for interstate gas or to contracts entered into after April 20, 1977. The Act was challenged as a violation of the U.S. Constitution which prohibits a State from passing a "Law Impairing the Obligation of Contracts."[2] The Kansas Supreme Court upheld the constitutionality of the statute on the grounds that it was reasonable and necessary to serve an important public purpose, and was appropriately limited in time and scope.[3] The U.S. Supreme Court heard oral arguments in the case on November 9, 1982. If the statute is upheld, a State could limit the impact of indefinite price escalator clauses as applied to gas produced and sold within its own borders. The two States with the largest intrastate markets, Texas and Louisiana, have passed no such statutes.

Within a State, the intrastate market is far from homogeneous. Two very different purchaser classes exist: direct-sale customers and pipeline companies. In 1978, direct sales accounted for about one-third of all intrastate sales, with an average price less than half of the average price paid by pipeline companies [24]. In addition, direct-sale purchasers had a significantly higher proportion of contracts without indefinite price escalation clauses. Over 70 percent of these contracts predate

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[1] Kan. Stat. Ann., 1980 Supp., S. 55-1401 et seq.

[2] U.S. Constitution, Art. I., S. 10, clr. 1.

[3] Energy Reserves Group v. Kansas Power and Light, 630 P.2d 1142 (Kan. 1981), probable jurisdiction noted, 102 S. Ct. 1748 (1982).

1970, and over 50 percent will expire by 1985. Thus, although the prices for direct-sale customers are very low on the average, purchasers may be faced with sudden large increases in price when their contracts expire. The direct-sale purchaser is usually a large industrial customer or an electric utility. Problems involving long-term contracts occur in the intrastate markets, but are solved at the local level. In Texas, the most visible problem occurred in the Lo-Vaca Gathering Company case where Lo-Vaca, an intrastate supplier, overcommitted and was forced to default [15]. In Louisiana, Texaco announced in 1980 that its reserves could not support its contract commitments. Recently, Texaco reached new agreements at considerable cost with three direct purchasers whose previous contract terms could not be met [59].

Natural Gas Consumption

Short-run changes in end-use consumption of natural gas are caused by a variety of major factors: natural gas prices relative to alternative fuels; weather; national income levels; industrial activity; and curtailments. In the past 5 years, the interstate market has gone from severe curtailments to substantial oversupply.

In 1982 natural gas delivered to consumers was down 8 percent from 1981 with a considerable amount of potential production "shut in." Over 80 percent of the decline was in industrial consumption of natural gas which declined by a dramatic 17 percent from 1981 to 1982 [64].

More specifically, the decline reflects decreased industrial consumption in the States of Texas, Oklahoma, Arkansas, and Louisiana. The consumption in these four States accounts for approximately 41 percent of total industrial consumption of natural gas [32]. Recently available evidence indicates that 70 percent of the volume of natural gas consumed by large industrial boilers in 1979, which may have represented as much as 16 percent of total industrial natural gas consumption, could have been switched to alternative fuels with minor adjustments in the boilers [30].

In general, industrial purchasers of direct sales in the intrastate markets can be characterized as large petrochemical and agricultural companies, such as refineries and fertilizer companies. These firms can be categorized into two groups: high conservation potential and low substitution potential. Firms with high conservation potential (for example, refineries) must decide whether additional conservation is justified on the grounds that the price of natural gas could change dramatically when their contracts expire and/or are deregulated.

Those firms with low substitution possibilities, principally where natural gas is used as a feedstock, are faced with foreign competition for their products. Because natural gas is more expensive to transport than are liquids and solids, it is economically advantageous when industrial processes that do not have readily available substitutes for natural gas are located near where the gas is produced.

Currently, in the Middle East and other areas of the world, gas is flared or in excess supply, much as it was in the United States 3 decades ago. Because flared gas has a low marginal value, any firm locating close to such a source could achieve a competitive advantage, given a stable political environment. Thus many industrial firms, primarily those in the intrastate market, are facing increased competition from abroad.

From 1975 through 1980, gas consumption by electric utilities increased nationally. The increase occurred in regions where oil previously had replaced natural gas during the shortage of natural gas supply. The availability of large amounts of gas and the favorable gas price relative to oil encouraged this change. During the same years, in regions where increasing amounts of coal-fired and nuclear-powered generation were available to satisfy demand for electricity, gas consumption declined. In 1981, gas consumption in electric utilities declined slightly to 3.7 quads.

In 1982 the amount of natural gas used in the generation of electricity declined again by over 10 percent to 3.3 quads. Electricity generation declined by 2 percent. This is the first time since World War II that electric generation has actually declined nationally. The large reduction in gas use is a consequence of the combined effects of this reduction in demand, the general substitution of coal and nuclear power, and a record year for hydroelectric generation (20 percent additional kilowatt-hours) as a result of heavy snowfalls in the West.

Recently, Texaco bought out of long-term contracts with Borden, Inc., and Louisiana Power and Light (LPL) [41]. For a reported $1.7 billion, Texaco reduced its commitment to sell gas to LPL, for about $0.30 per Mcf, by about half. LPL agreed to pay $1.20 per Mcf (at least one-third the current market price under new contracts) for its future purchases under this contract. In 1980, about 10 percent of all gas produced in the United States was purchased by electric utilities in Texas and Louisiana. For many electric utilities in the intrastate market, primarily Texas and Louisiana, the price of natural gas on a heat value basis currently is less than the price of coal. As these contracts expire and are decontrolled, prices could increase tenfold or more, creating very difficult decisions as to choice of fuels for the electric utilities.

Changes in the economic structure of society, such as the increased importance of services relative to manufactured goods, may tend to reduce the total consumption of natural gas; changes in the industrial structure may have an even greater impact. If, for example, the organic chemicals industry, which employs domestic natural gas as both a fuel and a feedstock, continues to decline in importance, this will have a noticeable impact on the total volume of domestic gas sales in this country. A continuation of the trend toward smaller families and more energy-efficient houses will also tend to reduce energy consumption and, consequently, natural gas consumption. Such characteristics of our society are important to natural gas markets and, along with changes in relative prices and economic activity, are critical indicators of the natural gas market's future direction.

Alternative Fuels

Where natural gas is available, there is competition with other fuels, but the competition is quite different among regions and consuming sectors. Although not yet a significant part of the transportation market, natural gas fueled vehicles are technically feasible, are environmentally preferred, and operational on a small scale. In the other sectors, residential, commercial, industrial, and electric utilities, natural gas is a significant part of the market.

The largest part of the residential energy market is home heating. In the residential sector, the fuel choice decision for home heating is usually made by the builder or homeowner when an existing system needs replacement. The prime competitors of natural gas heating are No. 2 fuel oil and electricity. A replacement decision requires an assessment of capital equipment and fuel costs over the life of the equipment. The difficulty and the importance of this choice have increased because most fuel costs are rising faster than inflation, requiring a larger portion of disposable income. The complexity has been compounded by the advent of new commercially feasible technologies such as the heat pump and high-efficiency furnaces, and conservation alternatives.

The industrial sector uses natural gas as a feedstock, as a direct heat source, and to raise steam in boilers. In the first two uses, the alternative fuel choices are either not possible or require very expensive equipment changes, but for steam generation, especially for large boilers, in many cases the capital expenditures have already been made to burn either natural gas or No. 6 fuel oil. Many analysts believe that No. 6 fuel oil prices will set the market price of natural gas.

Residual (No. 6) fuel oil prices are highly volatile. The average wholesale price of No. 6 fuel oil has ranged from $11 (in 1976) to $29 (in 1981) per barrel. The price of residual fuel oil over the next decade has four principal determinants: the world oil price, the demand for motor gasoline and No. 2 fuel oil, the economics of upgrading No. 6 fuel oil to higher distillates, and the No. 6 fuel oil demand, both domestic and foreign. Residual fuel oil is currently a refinery by-product of the higher grades of petroleum products.

As long as the capacity to upgrade residual fuel is not available, and the demand for higher distillates exists, residual fuel will be produced and, if necessary, discounted to sell. This discount may be greatest where there is a marginal fuel choice decision, the dual-fired boiler. Since natural gas prices contain a high portion of fixed costs, volatile fuel switching can create serious problems in gas markets as currently structured.

Electric utilities use natural gas in radically different ways. Because of older long-term contracts, the average price of firm (noninterruptible) sales to electric utilities is lower than the average price of interruptible sales [36]. In the Southwest, cheap gas under long-term contracts is used to fire baseload elecric power generation. When these contracts expire, the economics of generation will change significantly, with the likely alternative being coal. Already many electric utilities in the Southwest have built new coal-fired baseload generating plants.

In other parts of the country, gas use is low in the summer and gas is sold at reduced rates for load balancing to electric utilities to service peak loads caused by air conditioning.

Currently, many distributors and pipelines have successfully petitioned their regulatory commissions and have been granted special tariffs for customers with the capability of switching to alternative fuels. A case may be made that losing these customers would increase the rates of all customers, but this can only be true for a limited range of prices.

Simple rules for natural gas pricing based on alternative fuels are dangerous. In an unrestricted natural gas market with abundant low cost supplies (for example, greater than 22 quads per year) the alternative fuel may be coal. In a market with very little supply (for example, less than 14 quads) the alternatives may be No. 2 fuel oil and electricity. In between these two possibilities, the greatest share of marginal competition is with residual fuel oil. Further, since transportation costs and environmental regulations are different between competitive fuels and natural gas, geography also plays an important role in determining the alternative fuel.

In this chapter, some of the issues facing the natural gas market and its interest groups were presented. The evolution of the natural gas markets will also depend on external forces such as the price and availability of oil, and the availability of capital to finance fuel conversion projects. These issues, ranging from regulatory rate design to the basic structure of the industry, are presented not just for intellectual discussion, but to illustrate in the natural gas markets the built-in changes prescribed by the NGPA.

4. THE NATURAL GAS MARKET THROUGH 1990 UNDER THE NGPA

Assumptions and Approach

Projections into the future depend critically on the assumptions, both implicit and explicit, that are made in the course of an analysis. (The assumptions underlying the present study are summarized in Appendix B.) Several assumptions are critical to an analysis of the market for natural gas over the next decade. In order to construct base-level demand schedules for gas, assumptions must be made about the performance of the economy and the availability and price of supplemental and alternative fuels, which are based on underlying assumptions about economic growth and world oil prices. The GNP is projected to grow at 2.1 percent (per annum) from 1980 through 1985 and 2.9 percent from 1985 through 1990. The world oil price is projected to fall in real terms through 1985, then increase steadily to $37 per barrel (in 1982 dollars) in 1990. On the supply side, assumptions must be made about discovery rates and production costs for natural gas. Supply from unconventional sources is projected to contribute about 23 Quads of reserves through 1990.

An important factor affecting the price of gas is the purchase (take) strategy of the pipeline system. The assumption in this analysis is that after satisfying take-or-pay obligations, a pipeline system purchases the mix of gas that minimizes purchase gas costs in any year. This naive assumption does not allow for the husbanding of low cost gas for future use or other more complicated take strategies. Further, if the pipeline system cannot market gas at its minimum take-or-pay, the system defaults on its high priced contracts in order to obtain an average price that is marketable.

A factor affecting the delivered cost-of-gas by sector is the allocation of downstream costs in the pipeline system. In this analysis, there are no provisions for temporary and isolated shifts in the allocation of costs to customer classes. The basic rate structure, the method of allocating costs, remains the same throughout the forecast horizon. For example, there are no special pricing provisions to allow pipeline companies and distributors to maintain industrial customers with the potential of fuel switching.

A second factor affecting the results of the analysis is the methodological approach used. (An overview of this analytic approach is presented in Appendix A.) In this study, unlike previous ones, the natural gas market is modeled as two loosely coupled markets: one, reserve acquisition, in which pipeline systems bid and contract for reserves on the basis of existing commitments and projected sales, and the other market involving the purchase, delivery, and consumption of natural gas at the burner tip. These markets are coupled when reserves are purchased along with imports and spot purchases. The reserve acquisition market has a long-term perspective of 10 years or more whereas the production, delivery, and consumption market has a short-term perspective of a year or less. Because the long-term perspective often preempts the short-term perspective, the short-term market is rigid and is not able to adjust quickly to market events; as such, it can experience shortages, excess supply, and sometimes both simultaneously.

The history of the natural gas market indicates that shortages arise from time to time in both interstate and intrastate markets caused by regulations and the market infrastructure. Since a shortage, or excess demand, is hard to measure and project, in this analysis an additional source of energy has been made available to pipeline systems in order to allow markets to clear. This source of energy is priced at 130 percent of No. 2 fuel oil and is made available in unlimited quantities. This "supplemental source" can be considered as a combination of the following: spot market purchases, synthetic gas, additional imports, load loss to other energy sources (primarily oil) and curtailments. Currently, the most likely source of supplemental energy for the gas market is imported gas from Canada and Mexico. Both countries have excess production capacity and ample reserves. Consequently, barring political considerations, an additional 2 Quads per year or more could be made available by the late 1980's.

A third factor in the analysis is the input data. Since almost all analytic approaches require input data from multiple sources, the compatibility, consistency, and accuracy of the data are always issues (as discussed in Appendix B). Consequently, assumptions about basic input data are also important factors in the analysis.

In the remainder of the chapter the market behavior under the NGPA through the 1980's is examined. Additionally, sensitivity of the results to assumptions and parameters used to specify the reference case are presented to examine the resulting changes.

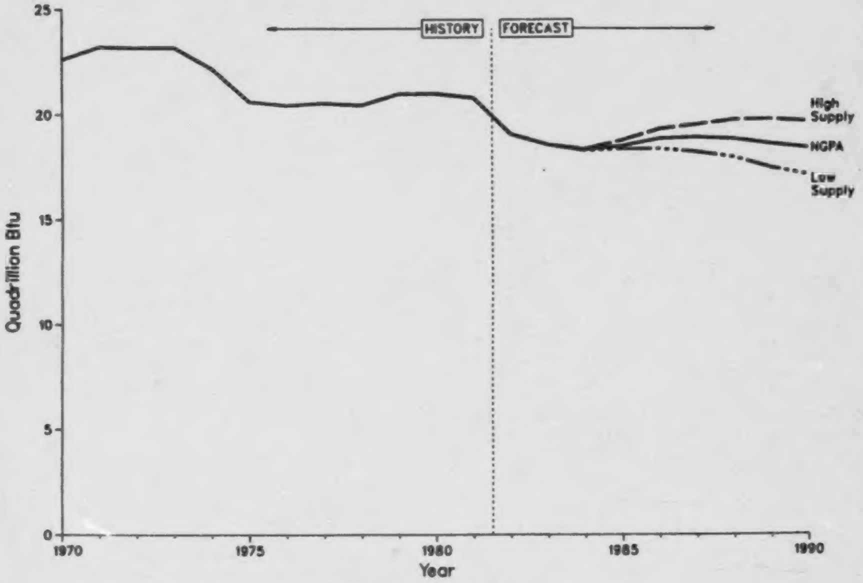
Market Behavior Under the NGPA

Under the NGPA, marketed production at a level of about 18.4 quads in 1990 is expected to be similar to the 1985 level (see Figure 4). The average wellhead price is projected to increase 10 percent annually (in constant dollars) from 1981 through 1984 (see Figure 5). A fly-up of 17 percent in the 1985 price is evident and results from a combination of several factors. Some gas that is decontrolled has a price governed by the price of oil and is, therefore, sensitive to world oil price assumptions. Also, the contract price for all new gas reserves is set at the market level for the first time. The size of the fly-up is affected by take strategies and by consumer conservation and fuel switching. The fly-up is 23 percent in the intrastate market compared to 14 percent with the interstate market. Increasing at about 9 percent annually in real terms after 1985, the average wellhead purchase price is projected to reach $4.88 per MMBtu (in 1982 dollars) by 1990.

By 1990, with rising world oil prices after 1985, declining discovery productivity, and the demand for gas projected to remain constant from 1990 through 1995, the new contract price is about $6 per MMBtu (in 1982 dollars). In 1990 approximately 20 percent of flowing gas (see Figure 6) is still under controls, allowing new contract prices to be rolled in, that is, averaged with lower priced gas.

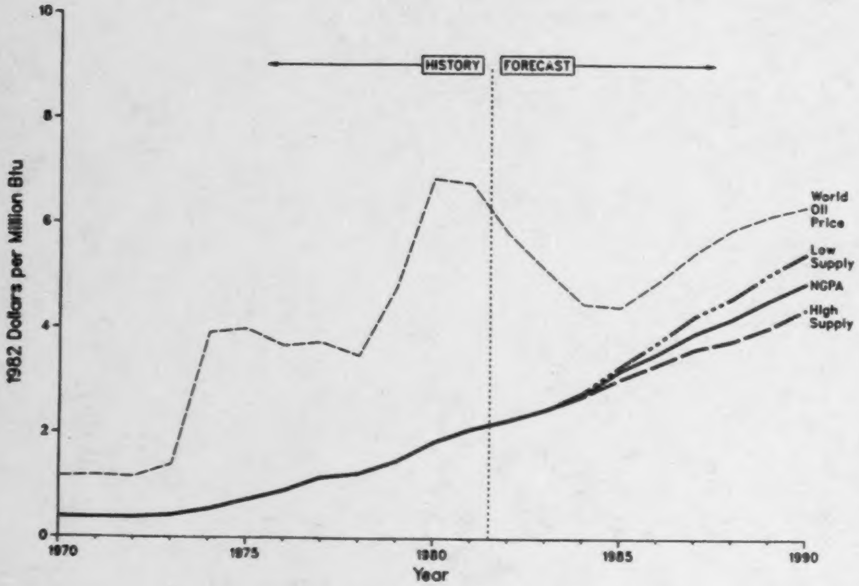
The amount of old gas production (from pre-1977 wells) declines exponentially during the 1980's from about 14 Quads in 1981 to about 4 Quads in 1990 (see Figure 6). To sustain production, this decline must be displaced by higher-cost production from new wells. Due to long-term contracts and NGPA price ceilings, old gas is priced under the average market price, but there are extreme differences in the price regulations on old gas, depending on its dedication status. In the interstate market, all old gas is tightly price-controlled. In the intrastate markets, the price ceilings are higher and about 30 percent is deregulated in 1985. By 1990, the average price of old intrastate gas is over 2 times the old interstate price (see Table 2), giving the interstate systems considerable advantage in the ability to roll in the price of new gas.

Figure 4. Natural Gas Production Under the NGPA and Supply Sensitivity



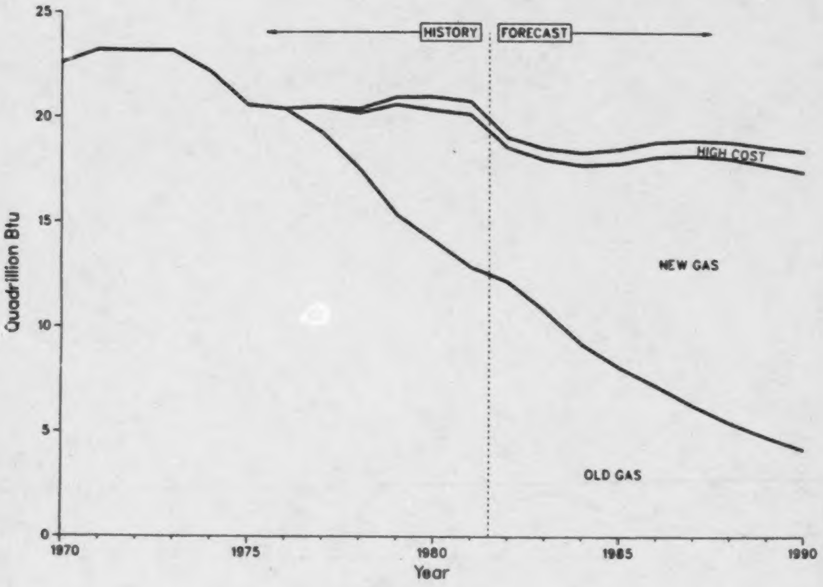
Source: Historical data, Annual Report to Congress 1981, Table 45, p. 103; forecast data, Gas Analysis Modeling System.

Figure 5. Average Wellhead Price Under the NGPA and Supply Sensitivity



Source: Historical data, Annual Report to Congress 1981, Table 51, p. 115; forecast data, Gas Analysis Modeling System.

Figure 6. Old, New, and High-Cost Natural Gas Production Under the NGPA



Percent of Total Production

	1985	1990
Old Gas	44	23
New Gas	52	72
High-Cost Gas	4	5

Source: Historical data, Annual Report to Congress 1981, Table 45, p. 103; forecast data, Gas Analysis Modeling System.

Reserves of natural gas decline from 1981 to 1990 to a level of 153 Quads (see Figure 7) under the NGPA due to a decrease of both supply and demand requiring less reserve inventory. A significant portion of these reserves (approximately 23 Quads) consists of unconventional gas from tight formations. Production over this period is 11 percent more than additions to reserves.

Table 2. Purchases and Average Prices of Gas by Markets and Category (Quantities in Quadrillion Btu; Prices in 1982 Dollars per MMBtu)

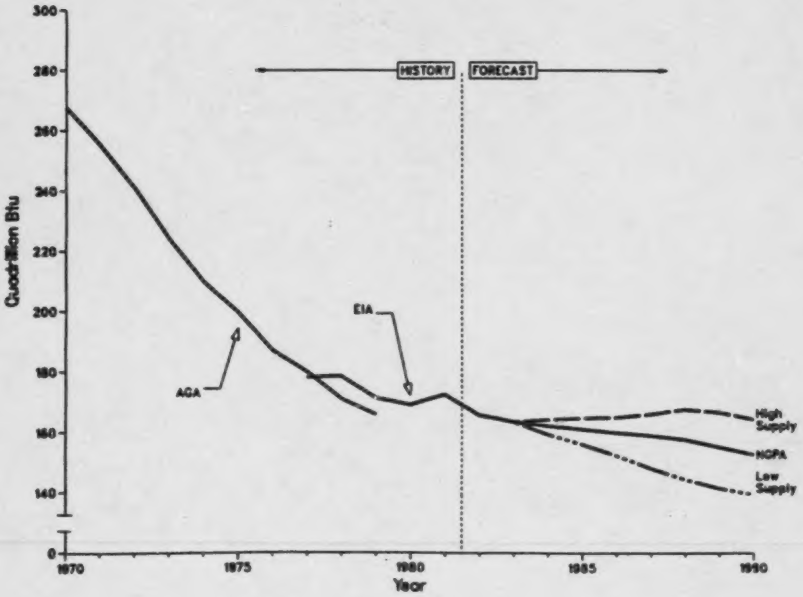
	Estimated	Projected	
Category	1981	1985	1990
Interstate Purchases			
Old Gas[a]			
Quantity	8.1	4.5	2.4
Average Price	1.29	1.40	1.56
New and High-Cost Gas[b]			
Quantity	4.6	6.9	9.0
Average Price	3.28	4.22	5.64
Total			
Quantity	12.7	11.4	11.4
Average Price	2.01	3.11	4.78
Intrastate Purchases			
Old Gas[a]			
Quantity	6.1	3.6	1.7
Average Price	2.07	2.84	3.64
New and High-Cost Gas[b]			
Quantity	1.4	3.5	5.2
Average Price	2.29	3.83	5.51
Total			
Quantity	7.5	7.1	6.9
Average Price	2.11	3.33	5.03

[a] Old gas is defined as gas purchased under Sections 104, 105, and 106.

[b] New and high-cost gas is defined as gas purchased under Sections 102, 103, 107, 108, and 109 (i.e., all categories other than old gas).

Source: 1981 estimated data are based on total production of 20.2 Quads and an average wellhead price of $2.04/MMBtu (see Table ES2) The distribution between inter- and intrastate purchases and prices is based on distributions from the Gas Analysis Modeling System (GAMS). Projected data are from the GAMS.

Figure 7. Natural Gas Reserves (excluding Alaska) Under the NGPA and Supply Sensitivity



Source: Historical data, EIA: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1981 Annual Report, AGA: American Gas Association, American Petroleum Institute, and Canadian Petroleum Association (published jointly), Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada, reports for December 31, 1970-1979, Volumes 25-34. Total reserves are reduced by Alaskan reserves. Forecast data are from the Gas Analysis Modeling System.

By 1990, the average wellhead purchase price of both interstate and intrastate pipelines increases by more than 100 percent. During this period, the combination of demographic factors, depletion of cheap old gas in the interstate market, and lower transmission charges combine to keep intrastate and interstate market shares at the wellhead about the same.

Residential consumption after increasing slightly from 1981-82, declines slowly to a level slightly below the 1981 consumption in 1990 (see Figure 8). The average residential price increases by about 86 percent between 1981 and 1990, to about $8.40 per MMBtu in 1982 dollars (see Figure 9). Total industrial consumption after falling 17 percent in 1982 increases by less than 10 percent by 1990. Consumption by electric utilities remains at 1982 levels, with prices doubling in real terms. Overall consumption declines through 1983 but stabilizes in the 1985 to 1990 period (see Figures 10 and 11 and Table 3). Prices rise significantly in all regions. Some electric utility and industrial gas demand in regions is lost to fuel-switching when the price of residual fuel oil is lower than the delivered gas price.

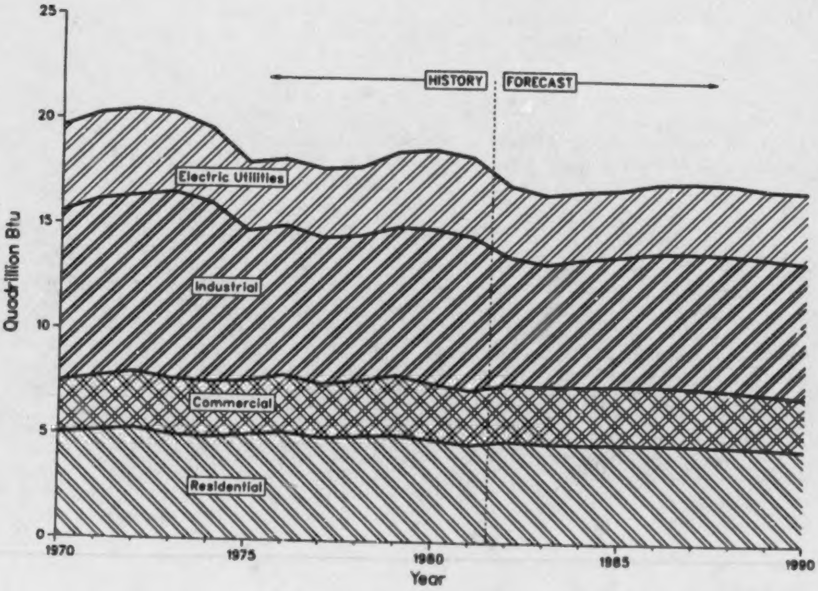
Sensitivity of the Reference Case to Changes in Assumptions

The forecasts in this chapter represent an internally consistent view of natural gas supply and demand, based on specified assumptions. In this section, the reference case is viewed generally as a constant, while selected parameters of the reference case are varied. In particular, parameters are varied to create high and low supply estimates and high and low demand estimates. By changing these parameters in the reference case, the sensitivity of the longer-term forecast to the assumptions and data used in the analysis can be examined.

To examine the sensitivity to supply, parameters considered critical to the supply projections were changed (see Appendixes A and B). These changes represent major uncertainties affecting the future supply of gas. Natural gas reserves are estimated, not measured, quantities, and thus are subject to uncertainty. Finding rates, a measure of productivity of the exploration effort, have always been difficult to measure or estimate and have in the past caused considerable debate among analysts and decision-makers. Finally, the most important cost factor in exploration and production of crude oil and natural gas is drilling costs. For low supply the changes included decreasing the finding rates and increasing drilling costs. In the high supply case, the same parameters were changed in opposite directions.

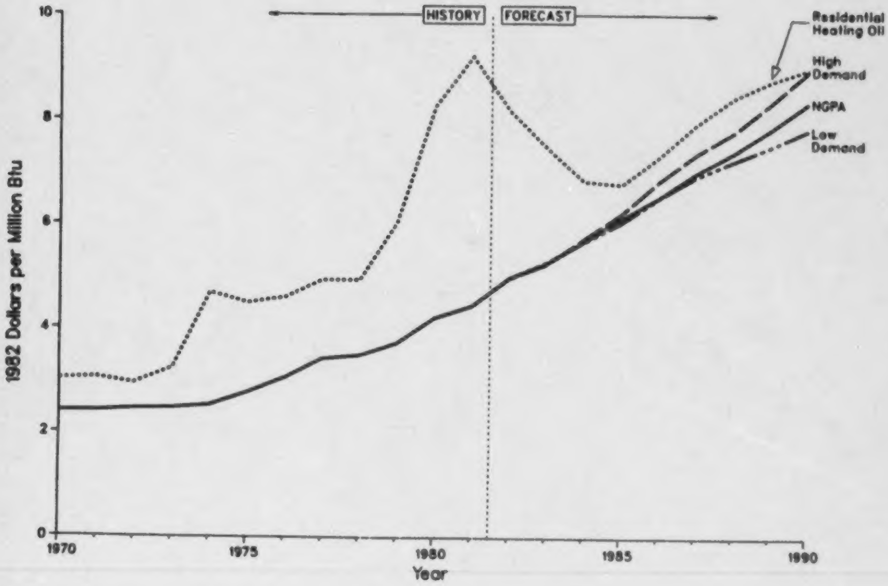
Under the lower supply assumptions, production is 17.1 Quads in 1990, 7 percent less than the reference case. Lower supply induces higher prices and a need for additional "supplemental sources" with an average wellhead price that is 11 percent higher than the reference case by 1990 (see Figure 5). The price of new contracts is 11 percent higher. Reserves are about 13 Quads lower than the reference case by 1990 (see Figure 7), and the interstate share of the purchased gas market remains at about the same level as in the reference case. The 1990 average residential prices increase by 8 percent over the reference case.

Figure 8. Consumption of Natural Gas by End-Use Sector Under the NGPA



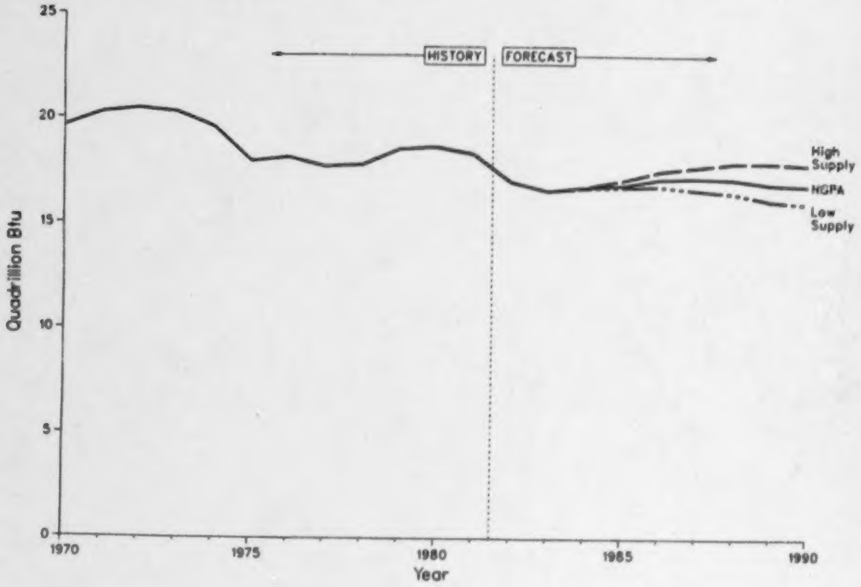
Source: Historical data, Annual Report to Congress 1981, Table 47, p. 107; forecast data, Gas Analysis Modeling System.

Figure 9. Average Price of Natural Gas Consumed by Residential Sector Under the NGPA and Demand Sensitivity



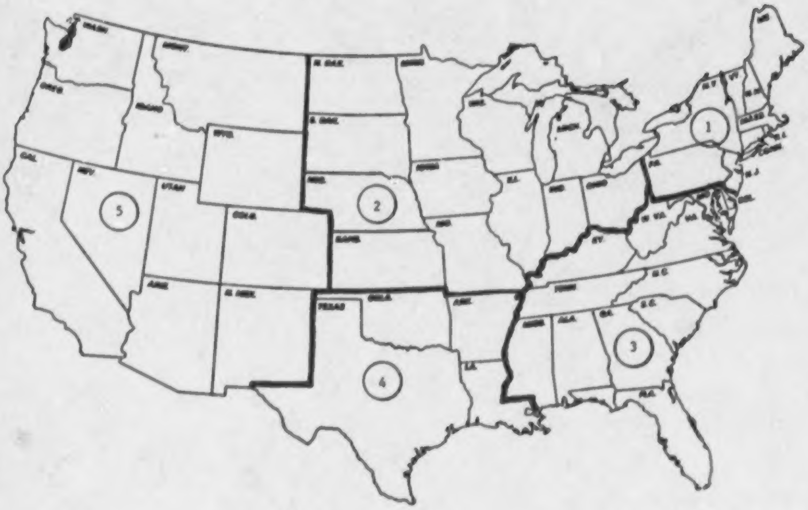
Source: Historical data, Annual Report to Congress 1981, Table 52, p. 117; forecast data, Gas Analysis Modeling System.

Figure 10. Total Consumption of Natural Gas Under the NGPA and Supply Sensitivi



Source: Historical data, Annual Report to Congress 1981, Table 47, p. 107; forecast data, Gas Analysis Modeling System.

Figure 11. United States Consumption Regions



Region 1 (Northeast): Connecticut, Maine, Massachusetts, New Jersey, New Hampshire, New York, Pennsylvania, Rhode Island, and Vermont.

Region 2 (Central): Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, and Wisconsin.

Region 3 (Southeast): Alabama, Delaware, District of Columbia, Florida, Georgia, Kentucky, Maryland, Mississippi, North Carolina, South Carolina, Tennessee, Virginia, and West Virginia.

Region 4 (Southwest): Arkansas, Louisiana, Oklahoma, and Texas.

Region 5 (West): Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming.

Under higher supply assumptions, there is a smaller (12 percent) fly-up in wellhead prices in 1985 (see Figure 5). By 1990, the average wellhead price is lower than under the reference case and the new contract price is 13 percent lower. Additionally, reserves are 12 Quads higher.

To examine the sensitivity of the reference case to demand assumptions, the base demand was varied (for details see Appendixes A and B). For high demand, the consumption is 6 percent higher than the reference case by 1990, with an average price increase of 10 percent. The increased consumption is satisfied by "supplemental sources". The new contracts price is about 17 percent higher in anticipation of higher demand in the 1990's.

Table 3. Regional Consumption Volumes (Quadrillion Btu) and Prices (1982 Dollars Per Million Btu) of Natural Gas Projected for the NGPA Reference Case

	Actual	Projected	
Region	1981	1985	1990
Northeast			
Quantity	2.26	2.09	2.06
Price	4.92	7.05	9.39
Central			
Quantity	4.93	4.62	4.67
Price	3.74	5.29	7.39
Southeast			
Quantity	2.31	2.04	2.17
Price	3.78	5.74	7.88
Southwest			
Quantity	5.84	5.33	5.04
Price	2.75	3.91	5.91
West*			
Quantity	2.86	2.77	2.93
Price	4.10	5.41	7.54
Total*			
Quantity	18.20	16.84	16.87
Price	3.63	5.14	7.28

*Excludes Alaska.

Source: Gas Analysis Modeling System. Data for 1981 are from the *Natural Gas Annual*.

For low demand, the consumption in 1990 is 7 percent lower than the reference case with a decrease of approximately 10 percent in the average price to consumers. By 1990, residential and commercial consumption is about 10 percent lower and prices are 6 percent lower than the reference case. Consumption of natural gas by electric utilities decreases by 4 percent, and industrial consumption decreases by 4 percent. With anticipated lower demand, the new contracts price in 1990 is 29 percent lower than the reference case.

In the course of the analysis, the sensitivity of the natural gas market to overexpectations on the part of pipeline systems was examined. Overexpectation occurs when a pipeline system, during the process of acquiring reserves, has higher expectations of its ability to market gas than are realized when the gas is actually marketed, often 10 years or more after the reserves were acquired. Overly optimistic assumptions on the part of the pipeline purchaser of future demand growth and expected prices, cause pipelines to overbid and acquire more reserves than necessary, leading to overpriced excess supply. This situation can lead to take-or-pay problems and excess deliverability, with prices increasing as demand decreases. Under these conditions, gas prices rise rapidly, consumption (especially industrial) falls, and reserve inventories increase, due mainly to the lack of appropriate market signals between the wellhead and burner-tip markets. Underestimating demand growth leads to lower bid prices and, consequently, less reserve acquisitions. If this situation persists, the potential for shortages and curtailments increases. Additionally, market rigidity can lead to situations of shortages and excess supply at the same time in markets segregated by regulations.

The price of crude oil affects the natural gas market in many ways: at the wellhead, the supply of gas is affected, in the industrial and electric utility sector the alternative fuel price is primarily set by the crude oil price. At the wellhead, increased oil prices create incentives to drill and stimulate activity, but for the most part this activity is directed toward oil. Since the search for oil and gas cannot be completely separated, the effect of oil prices on gas discoveries and production is difficult to estimate. Increases in oil prices (and excess gas production capacity) would "tilt" the search toward oil but gas can be found accidentally and in contact with oil. Decreases in oil prices create internal cash flow and financing difficulties for exploration and production companies, which would reduce overall activity levels, but could "tilt" exploration and development toward gas.

At the burner tip, residual fuel (No. 6) oil is the principal competitor with gas in the industrial and electrical utility sectors. The primary component in the price of residual fuel oil is the price of crude oil. The sulfur content causes about a 20 percent variation in price. In the short term, residual fuel oil is often discounted when sold to end-users with dual-fired boilers.

In the general economy, a decreasing oil price causes a lower balance of payments leaving more money to spend in the domestic markets. Demand is stimulated because there is more spending power and industrial input costs are reduced.

If the world oil price should remain as low as $28 per barrel until 1990 (in 1982 dollars), 25 percent less than the reference case, natural gas demand could be expected to be reduced considerably. If world oil prices increase to $48 per barrel in 1990 ($11 more than the reference case), the combined effect of these changes would increase the projections of 1990 natural gas demand. The greatest impact of world crude oil prices on the natural gas market is in the competition of natural gas and residual oil in the industrial and electric utility sectors.

Issues Not Quantitatively Addressed in the Analysis

Although quantitative models force users to specify exactly how certain issues will be treated, this approach also makes clear issues that are not addressed quantitatively. In this analysis, the intrastate markets in Texas and Louisiana were analyzed by aggregating end-use consumers into six sectors. Currently, this approach does not separate these markets into an additional dichotomy, direct and pipeline purchases. Direct purchases involve mainly large industrial and electric utility customers, that have individual contracts with producers. These consumers are important marginal consumers of natural gas (as discussed in Chapter 3).

In the interstate market, both pipeline and distribution companies are requesting and in some instances have already obtained special tariff provisions, that is, the reallocation of costs, to reduce the price to customers with dual-fired capability. If this new allocation of costs becomes widespread, and the crude oil price is less than projected, the prices to residential and commercial customers would most likely rise by larger amounts. Nevertheless, failure to implement special tariffs could also result in higher prices for residential and commercial customers due to load loss.

Further, increased costs to the residential customer cause uncollectables (unpaid customer bills) to rise. Since most public utility commissions do not allow gas deliveries to residential customers to be shut off in the winter, the cost of uncollectable bills is allocated to the paying customers. Under the previous two conditions, residential prices could increase faster than currently projected.

Another issue that could become a factor, but as yet is not, is the increase in spot market purchases. Spot market purchases appear either in the form of "off-system" sales as currently authorized under the NGPA or simply the increase in short duration sales. Currently, these sales can be viewed as a part of supplemental sources but are assumed to take place at higher than market-clearing prices, although just the opposite could be the case in a market with excess supply.

Summary

Under the NGPA, natural gas production and consumption decline through the 1980's. The average wellhead price rises as do consumer prices. Results and conclusions can vary considerably depending on the sensitivity of the assumptions and changes in the parameters. Because of considerable amounts of gas under price controls, the new contract price for gas is artificially high and the end-use price is artificially low. Under these conditions, additions to reserves do not keep pace with consumption.

5. ALTERNATIVES TO THE NGPA

The NGPA was apparently intended to provide a smooth transition to a decontrolled natural gas market at the wellhead, thus correcting the imbalance in the dual market structure in most large producing states. Mainly, through the PIFUA, prohibitions were placed on consumption of natural gas limiting its markets. However, the unexpected jump in world oil prices in 1979 caused the gas price ceilings specified by the NGPA to become restrictive, and some contract provisions were negotiated that are widely believed to be troublesome (for more information on the contract problems see [2]).

A number of proposals have been made to deal with these problems. This chapter looks at three alternatives to the NGPA: (1) the Administration proposal, (2) phased decontrol, and (3) continued controls. They represent widely differing sets of views on how to correct the perceived problems in the gas market.

The NGPA, as discussed in previous chapters, decontrols significant amounts of flowing gas and all future discoveries in 1985. Continued controls, essentially the removal of Section 121 of the NGPA, keeps all gas under the price ceilings as specified in the NGPA with the exception of gas already deregulated, which remains deregulated. Phased decontrol gradually increases all price ceilings in 1983 and 1984, to a level equal to 70 percent of the price of crude oil in the beginning of 1985, then removes all price ceilings. The Administration's proposal was described in Chapter 2.

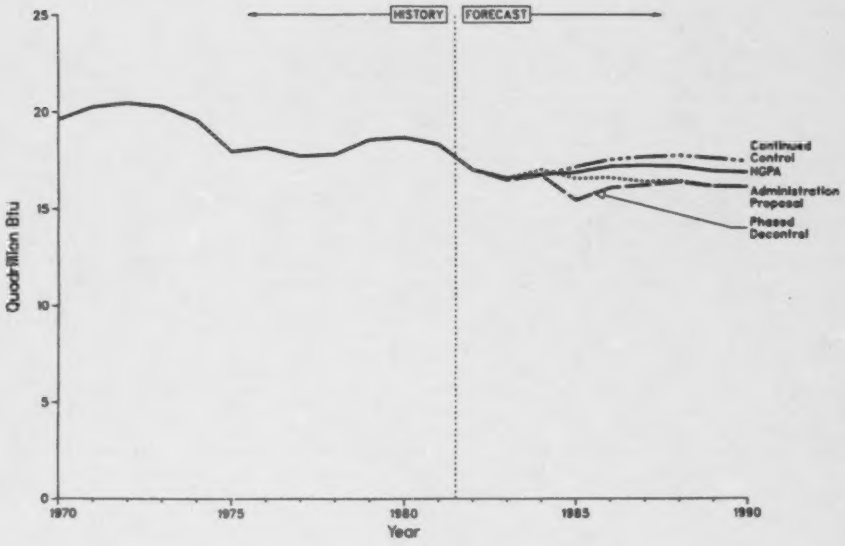
NGPA Review

As discussed in the previous chapter, average wellhead prices under the NGPA rise at about 10 percent annually (in constant dollars) from 1981 through 1990. A price fly-up of 17 percent is seen in 1985 as a result of partial decontrol of prices. The marginal price of new decontrolled gas contracts at the wellhead is 22 percent higher than the average price by 1990, reflecting a demand for new reserves to satisfy anticipated future demand and the roll-in capacity created by remaining price ceilings.

As shown in Figure 12, consumption under the NGPA declines slightly through 1990. Production, which is determined both by demand and by average wellhead prices, keeps pace with consumption.

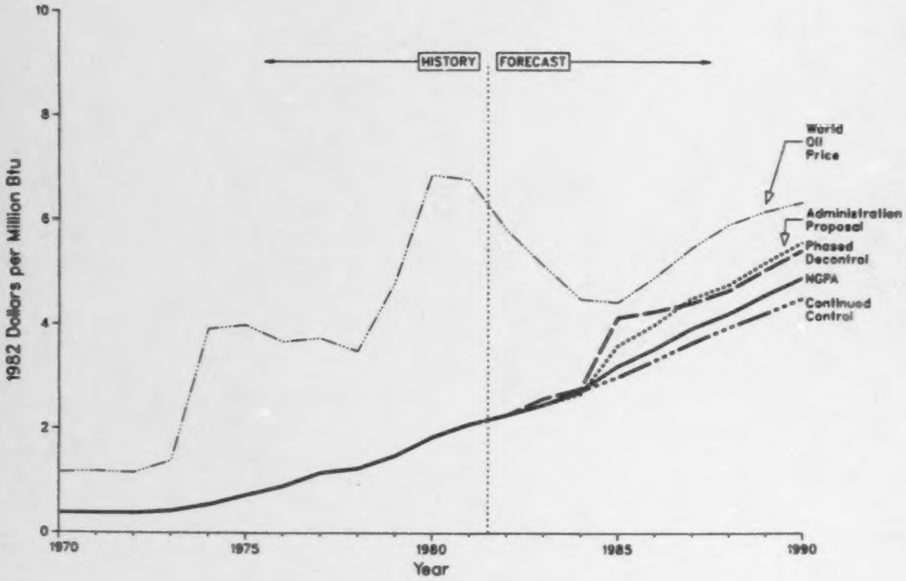
As shown in Figure 13, there is a "fly-up" in the average wellhead price in 1985. The wellhead price "fly-up" in 1985 has little immediate effect on reserve additions since it reflects the decontrol of prices of gas already under contract, whereas reserve additions and reserves respond to the marginal prices bid for new contracts. Indirectly however, removing price controls reduces the cushion of lower priced gas against which new contract prices can be rolled in, thereby lowering the prices that can be bid for new reserves which in turn reduces the incentives for exploration. The reserves through 1990 decline slightly (see Figure 14).

Figure 12. Total Consumption of Natural Gas Under the NGPA and Alternative Policies



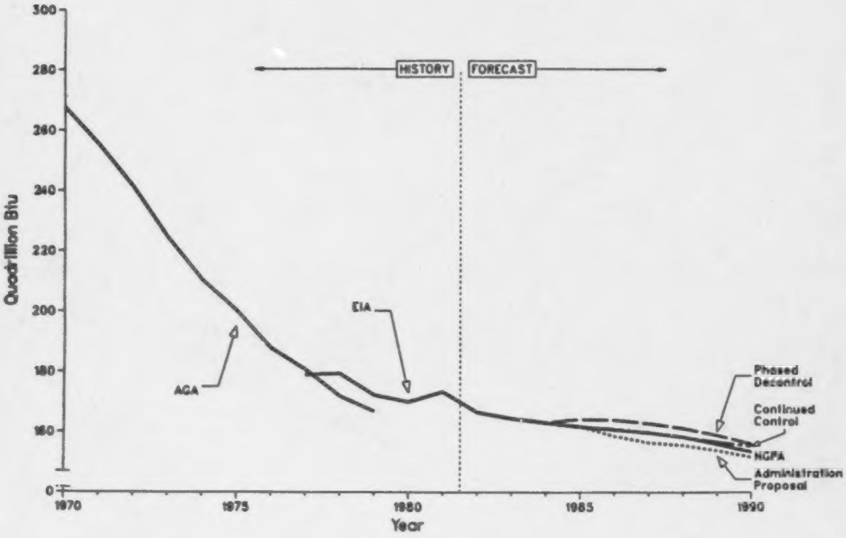
Source: Historical data, Annual Report to Congress 1981, Table 47, p. 107; forecast data, Gas Analysis Modeling System.

Figure 13. Average Wellhead Price Under the NGPA and Alternative Policies



Source: Historical data, Annual Report to Congress 1981, Table 51, p. 115; forecast data, Gas Analysis Modeling System.

Figure 14. Natural Gas Reserves (excluding Alaska) Under the NGPA and Alternative Policies



Source: Historical data, EIA: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1981 Annual Report, AGA: American Gas Association, American Petroleum Institute, and Canadian Petroleum Association (published jointly), Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada, reports for December 31, 1970-1979, Volumes 25-34. Total reserves are reduced by Alaskan reserves. Forecast data are from the Gas Analysis Modeling System.

Administration Proposal

In order to assess the Administration proposal quantitatively, assumptions must be made as to how the market will react. For example, if a pipeline system loses a major portion of its industrial and electric utility markets as a result of fuel switching in a given year, what will happen? There are several possibilities: the pipeline could request immediate renegotiation with its producers; the pipeline or the producer could attempt to sell the newly generated excess gas on a spot basis; or the purchaser could simply reduce its take, creating excess production capacity. The assumption that the gas market would become a spot market is difficult to defend because historically gas markets have operated under long-term contracts. In this study the excess capacity is permitted with spot market purchases available at 110 percent of the world oil price.

A second issue that has an important impact on the analysis is the assumption involving the rate of contract renegotiation. One argument maintains that since the process of contract carriage authorization would take so long at the Commission the purchaser would maintain an advantage in the renegotiation process. This advantage would allow quick downward price adjustments of high-cost gas and slow upward adjustments of old, low-cost gas. The assumption used in this study is that contract renegotiations in 1984 do not measurably change the conclusions and in 1985 the average price of all gas is renegotiated based on the new gas price. Further, it is assumed that the PGA mechanism does not delay in a signficant way the cost passthrough of interstate pipelines.

An additional assumption in the Administration proposal case is that there will be no additional gas produced or reserves added as a response to the decontrol of old gas in comparison to the NGPA reference case. This assumption was made because the evidence for such a response needs further detailed study, and the NGPA has provisions to permit such old gas response.

Under the Administration proposal case, a 35 percent increase in the average wellhead price occurs in 1985, as shown in Figure 13. After 1985, the wellhead price and the new contract price are assumed to vary only by a lagged adjustment in old contracts. Price ceilings are the lower of the NGPA ceiling or the gas cap price which reduces prices in 1984. After 1984, prices rise due to the decontrol of all gas and the assumptions on the adjustments under old contracts.

Under the NGPA, controls on old gas keep the average wellhead price below the price in the Administration proposal case past 1984. Since, under the Administration proposal, most gas wellhead prices are assumed adjusted by periodic renegotiations, based on the average new contract price, adjustments are automatic. In 1985, the new contract price forces existing delivered prices to industrial and electric utility users in the Southwest and West Coast above the residual fuel oil price and more fuel-switching occurs than under the NGPA. With the additional flexibility for new contracts under the Administration proposal adjustments could occur to reverse this process if an effective spot market evolves.

By 1990, the new contract price is lower, with a higher R/P ratio when compared to the NGPA. This situation indicates that the market is in better condition to operate in the 1990's under the Administration proposal.

Three assumptions in the Administration proposal cause higher wellhead prices than would otherwise be the case. First, under the market-out provisions, contracts are assumed to be rapidly adjusted to new contract prices. If the market adjustment process is slower than assumed, wellhead prices in the mid-1980's would be lower. Secondly, if additional reserves are added in old fields due to the Administration proposal, the wellhead price would decline in the late 1980's. Thirdly, if the proposed PGA pass-through mechanism dampens the increased wellhead costs from 1984 to 1985, the average wellhead price would be reduced by $.60 per MMBtu at an additional cost to the pipelines or foregone revenues to producers of about $11 billion.

Phased Decontrol

Under phased decontrol, wellhead price ceilings are increased using a formula that would bring the price to 70 percent of the world oil price by the end of 1984; then all price ceilings are removed in 1985. A 50 percent "fly-up" in average wellhead price in 1985 still occurs because the indefinite price escalators in the contracts for the gas not decontrolled under the NGPA force the price up based primarily on prices in the oil market. By 1990, the average wellhead price is 11 percent higher than under the NGPA. Despite the higher average wellhead prices under phased decontrol compared to the NGPA, the marginal price for new contracts is essentially the same, because not only is there a smaller cushion of low priced gas to support roll-in of higher prices, but higher prices to consumers encourage conservation.

As shown in Figure 12, consumption is reduced compared with the NGPA case by the higher average prices that prevail under phased decontrol. Although production is also less, as can be seen in Figure 15, higher prices and the decontrolled market at the wellhead ensure that there is sufficient production to meet the needs of consumers.

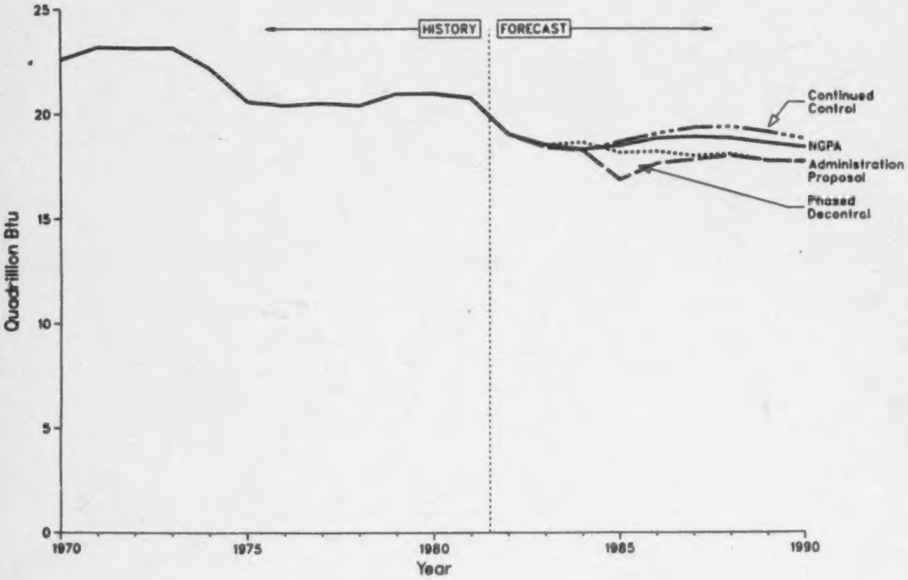
As shown in Figure 14, reserves under phased decontrol grow at essentially the same rate as under the NGPA. There are several reasons for this. First, the marginal decontrolled wellhead price under phased decontrol is generally lower than under the NGPA so that there is slightly less incentive to explore for and develop new reserves. This is counterbalanced by price-induced conservation in the later years reducing the rate of depletion of reserves. By 1990, the new contracts (marginal wellhead) price is quite close to that under the NGPA.

Continued Controls

Due to the continuation of price ceilings, average wellhead prices are lower than under the NGPA (see Figure 13) and the price increase in 1985 is 10 percent. By 1990, the average wellhead price is 8 percent below that projected under the NGPA. As a result of the lower prices to consumers, consumption under continued controls is higher than under the NGPA, as shown in Figure 12. Production is higher than under the NGPA after 1985, reflecting a partial accommodation to the higher consumption levels and the effects of lower wellhead prices. Even though production is slightly higher, it is insufficient to meet demand. By 1990, the requirement for supplemental sources has grown to 0.4 Quad. The need for supplemental supplies is greater in the intrastate markets in the Southwest.

The combination of a large cushion of relatively low controlled prices with higher anticipated demand for natural gas causes the marginal wellhead price for new decontrolled gas to be higher than under the NGPA by a factor greater than 2 between

Figure 15. Natural Gas Production Under the NGPA and Alternative Policies



Source: Historical data, Annual Report to Congress 1981, Table 45, p. 103; forecast data, Gas Analysis Modeling System.

1985 and 1990. Only a limited volume of gas (Section 107) can be bought at these higher prices, however, so that they have small impact on reserves. Because most wellhead prices for new gas remain under controls at levels lower than under the NGPA, there is less incentive to explore for and develop new reserves.

Regional Considerations

The impact of wellhead prices on consumers is affected both by the size of the transmission and distribution system needed to service a particular region (which depends upon the region's distance from producing areas) and by the extent to which the system operates at or near its capacity. Since most transmission and distribution costs do not vary as a function of the amount shipped, wellhead price increases, along with reduced quantities, tend to amplify prices when passed on to consumers. A wellhead price increase, for example, leads to some reduction of consumption, which in turn means that the fixed costs of transmission and distribution must be spread over smaller quantities, thereby further increasing the consumer price. On the other hand, regional shifts of consumption toward producing areas tend to decrease the transmission costs.

Under the Administration proposal case, residential prices compared to the NGPA reference case are higher in 1985 as seen in Table 4. Under phased decontrol, prices increase faster than under the NGPA reference case. The nationwide average residential natural gas price by 1990 in the continued controls case as compared with the NGPA case is lower. The largest impact occurs in the West.

The impact of continued controls as compared with the NGPA case on industrial prices, shown in Table 5, varies across regions similarly to that of the residential prices, with the nationwide average industrial natural gas price lower in 1990. Although average industrial prices are lower by only about 5 percent, the potential for curtailments is considerably higher under continued controls.

The producer revenues under the NGPA are compared to revenues under the alternative policy scenarios are shown in Table 6. Cumulative revenues from 1982 through 1990 are 7 percent higher under phased decontrol and the Administration proposal than under the NGPA reference case. Under continued controls, they are 4 percent lower than under the NGPA. Total revenues for 1982 through 1990 differ by 64 billion dollars between the continued controls and phased decontrol cases.

Summary

The NGPA appears to represent an unstable balance between higher prices and the need for "supplemental sources." In the continued controls case, prices are lower, but "supplemental energy" is needed in both the interstate and intrastate markets in order to either meet or curtail demand. Under phased decontrol, the average wellhead price rises faster than in the other cases, thereby inducing conservation and nearly eliminating the need for supplemental sources.

Under the Administration proposal, the average wellhead price and the average price delivered to consumers are slightly higher than the NGPA case by 1990, but the outlook for the 1990's, as indicated by the new contract price and the R/P ratio, is better than under the NGPA.

Table 4. Prices of Natural Gas in the Residential Sector by Region and Selected Years, for the NGPA and Alternatives (1982 Dollars per Million Btu)

Region	Case	Actual	Projected	
		1981	1985	1990
Northeast	Reference Case	5.59	7.83	10.39
	Administration Proposal	—	8.13	10.91
	Phased Decontrol	—	8.97	11.03
	Continued Controls	—	7.83	10.24
Central	Reference Case	4.07	5.66	7.81
	Administration Prposal	—	6.17	8.45
	Phased Decontrol	—	6.76	8.29
	Continued Controls	—	5.59	7.62
Southeast	Reference Case	4.58	6.37	8.47
	Administration Proposal	—	6.50	8.78
	Phased Decontrol	—	7.24	8.90
	Continued Controls	—	6.42	8.46
Southwest	Reference Case	3.97	5.14	7.30
	Administration Proposal	—	5.58	8.05
	Phased Decontrol	—	6.01	7.78
	Continued Controls	—	4.88	6.91
West*	Reference Case	4.07	5.57	7.85
	Administration Proposal	—	5.78	8.55
	Phased Decontrol	—	6.45	8.37
	Continued Controls	—	5.28	7.00
Total*	Reference Case	4.43	6.11	8.35
	Administration Proposal	—	6.48	8.96
	Phased Decontrol	—	7.14	8.87
	Continued Controls	—	6.01	8.05

*Excludes Alaska.

Source: Gas Analysis Modeling System. Data for 1981 are from the Natural Gas Annual.

Table 5. Prices of Natural Gas in the Industrial Sector by Region and Selected Years, for the NGPA and Alternatives (1982 Dollars per Million Btu)

		Actual	Projected	
Region	Case	1981	1985	1990
Northeast	Reference Case	4.17	5.85	7.65
	Administration Proposal	—	6.14	8.10
	Phased Decontrol	--	6.73	8.11
	Continued Controls	—	5.82	7.49
Central	Reference Case	3.47	4.83	6.83
	Administration Prposal	--	5.33	7.46
	Phased Decontrol	--	5.90	7.31
	Continued Controls	—	4.75	6.64
Southeast	Reference Case	3.63	5.29	7.34
	Administration Proposal	—	5.47	7.75
	Phased Decontrol	—	6.31	7.86
	Continued Controls	--	5.37	7.36
Southwest	Reference Case	2.60	3.79	5.81
	Administration Proposal	—	4.11	6.44
	Phased Decontrol	--	4.54	6.23
	Continued Controls	—	3.44	5.35
West*	Reference Case	3.99	5.27	7.35
	Administration Proposal	—	5.44	7.96
	Phased Decontrol	--	6.12	7.88
	Continued Controls	—	4.95	6.60
Total*	Reference Case	3.25	4.59	6.65
	Administration Proposal	—	4.91	7.23
	Phased Decontrol	--	5.50	7.12
	Continued Controls	—	4.38	6.31

*Excludes Alaska.

Source: Gas Analysis Modeling System. Data for 1981 are from the Natural Gas Annual.

Table 6. Producer Revenues by Year Under the NGPA and Policy Alternatives
(Billions of 1982 Dollars)

Year	NGPA Reference	Administration Proposal	Phased Decontrol	Continued Controls
1982	42.7	42.7	42.7	42.7
1983	45.3	45.3	47.1	45.3
1984	49.6	49.4	50.2	49.4
1985	58.8	64.8	69.1	55.5
1986	66.1	72.3	74.4	62.7
1987	73.7	80.4	77.9	70.0
1988	78.7	85.5	83.1	76.0
1989	84.4	91.6	89.1	80.1
1990	89.6	98.2	95.8	84.2
Total	588.9	630.2	629.4	565.9

Source: Gas Analysis Modeling System.

6. MACROECONOMIC EFFECTS AND IMPACTS ON HOUSEHOLD EXPENDITURES

The preceding chapter discussed the impact of the NGPA and alternative proposals on key aspects of the natural gas market. To complete the analysis, this chapter focuses on the broader implications for the economy as a whole and for individual household consumers.

The most obvious and direct impacts of various natural gas scenarios occur through changes in natural gas prices. For example, an increase in the price of natural gas at the wellhead is felt almost immediately as industries attempt to pass the higher energy costs on to both intermediate and final consumers. Indirect price effects occur as the higher-priced intermediate products push up non-energy material input prices; these indirect effects can be even more substantial than the direct effects. While the ultimate effect of this cost-push cycle on the inflation rate and the level of economic activity is in large part determined by how the monetary and fiscal policies are modified to adapt to the situation, the general price level will almost surely rise somewhat. This causes a decline in real income and consumption of both energy and non-energy commodities.

The analysis of macroeconomic effects for this study was done with the Data Resources, Inc. (DRI) quarterly model of the U.S. economy. The DRI model projects both direct and indirect impacts of changes in natural gas prices on the Consumer Price Index, other price indexes, the gross national product (GNP), and unemployment. While macroeconomic models such as the DRI model are important tools for analysis, they imperfectly capture the microeconomic phenomena of price controls and regulation. Thus, although the impact of natural gas price changes under each scenario can be projected reasonably well, the impact of the underlying changes to the regulatory structure of the natural gas market cannot readily be assessed. Since price controls often lead to misallocation of resources, changes in regulatory patterns will lead to changes in economic efficiency of production and consumption which tend to offset changes in prices, at least in the longer run. It is precisely these efficiency considerations that are poorly represented in macroeconomic models. Hence the analysis in this study may overstate the positive impact of lower prices under continued controls and overstate the negative impact of higher prices under decontrol cases.

Economic Projections Under the NGPA

In the reference case, under the NGPA, as shown in Tables 7, 8 and 9, the economy is projected to recover from its current recession starting in 1983. Projected real growth in GNP averages 4.5 percent over the 2 years 1983-85, while inflation, as measured by the rate of change in the CPI, is 4.9 percent annually over the same period. Unemployment continues to fall steadily to 8.3 percent by 1985. In the 1985-90 period, real annual growth in GNP is projected to moderate to 2.9 percent per year, while unemployment continues to fall and inflation rises to 7.0 percent over the period. It is against this backdrop that the alternative natural gas scenarios are measured.

Table 7. Comparison of Projected Macroeconomic Effects of Natural Gas Prices Under the NGPA Reference Case and Under the Administration Proposal, 1981 to 1990

	Real GNP (Billions of 1972 Dollars)			Percent	Consumer Price Index (1967 = 100)		Unemployment Rate (Percent)	
Year	NGPA Reference	Administration Proposal	Difference	Difference in GNP	NGPA Reference	Administration Proposal	NGPA Reference	Administration Proposal
1981	1,503	1,503	0	0.0	272	272	7.6	7.6
1982	1,476	1,476	0	0.0	289	289	9.7	9.7
1983	1,505	1,505	0	0.0	302	302	10.6	10.6
1984	1,577	1,577	0	0.0	316	316	9.4	9.4
1985	1,642	1,642	0	0.0	332	333	8.3	8.3
1986	1,694	1,690	-4	-0.2	353	356	7.9	8.0
1987	1,746	1,740	-6	-0.3	378	383	7.7	7.8
1988	1,792	1,785	-7	-0.4	406	412	7.6	7.8
1989	1,841	1,836	-5	-0.3	436	441	7.6	7.7
1990	1,898	1,895	-3	-0.2	466	471	7.5	7.5

Source: Simulation of DRI macroeconomic model.

Table 8. Comparison of Projected Macroeconomic Effects of Natural Gas Prices Under the NGPA Reference Case and Phased Decontrol, 1981 to 1990

	Real GNP (Billions of 1972 Dollars)			Percent	Consumer Price Index (1967 = 100)		Unemployment Rate (Percent)	
Year	NGPA Reference	Phased Decontrol	Difference	Difference in GNP	NGPA Reference	Phased Decontrol	NGPA Reference	Phased Decontrol
1981	1,503	1,503	0	0.0	272	272	7.6	7.6
1982	1,476	1,476	0	0.0	289	289	9.7	9.7
1983	1,505	1,505	0	0.0	302	302	10.6	10.6
1984	1,577	1,576	-1	0.0	316	316	9.4	9.4
1985	1,642	1,640	-2	-0.1	332	334	8.3	8.4
1986	1,694	1,689	-5	-0.3	353	357	7.9	8.0
1987	1,746	1,741	-5	-0.3	378	382	7.7	7.8
1988	1,792	1,787	-5	-0.3	406	412	7.6	7.7
1989	1,841	1,836	-5	-0.3	436	442	7.6	7.7
1990	1,898	1,894	-4	-0.2	466	472	7.5	7.5

Source: Simulation of DRI macroeconomic model.

Table 9. Comparison of Projected Macroeconomic Effects of Natural Gas Prices Under the NGPA Reference Case and Continued Controls, 1981 to 1990

	Real GNP (Billions of 1972 Dollars)			Percent Difference in GNP	Consumer Price Index (1967 = 100)		Unemployment Rate (Percent)	
Year	NGPA Reference	Continued Controls	Difference		NGPA Reference	Continued Controls	NGPA Reference	Continued Controls
1981	1,503	1,503	0	0.0	272	272	7.6	7.6
1982	1,476	1,476	0	0.0	289	289	9.7	9.7
1983	1,505	1,505	0	0.0	302	302	10.6	10.6
1984	1,577	1,577	0	0.0	316	316	9.4	9.4
1985	1,642	1,643	1	0.0	332	331	8.3	8.3
1986	1,694	1,696	2	0.1	353	352	7.9	7.9
1987	1,746	1,750	4	0.3	378	376	7.7	7.7
1988	1,792	1,794	2	0.1	406	405	7.6	7.6
1989	1,841	1,842	1	0.0	436	434	7.6	7.6
1990	1,898	1,898	0	0.0	466	464	7.5	7.5

Source: Simulation of DRI macroeconomic model.

Alternative Natural Gas Scenarios

In order to investigate the macroeconomic impacts of alternative natural gas scenarios, two sets of information were incorporated into the DRI model for each scenario. The first set is based on the assumption that the impact on the economy is felt solely through changes in the price and consumption of natural gas; the other considers the implications of requirements for "supplemental" energy supplies.

Natural Gas Price Impacts

Under the first set of assumptions, monetary policy adjusts slightly to accommodate general price pressures brought on by changes in the price of natural gas, but fiscal policy remains unchanged. Also, "supplemental" energy supplies do not affect other energy markets.

Under the Administration proposal case, natural gas prices are slightly below the NGPA through 1984; however, from 1985 to 1990 gas prices are higher with a substantial increase in the price of natural gas occurring in 1985. The higher gas prices force the inflation rate higher and slow the growth of the economy in the 1985-1990 period. As shown in Table 7, the difference in real GNP peaks in 1988 at $7 billion and declines thereafter. There is very little difference between the two cases by 1990.

Under phased decontrol, natural gas wellhead prices begin to rise prior to 1985, and then rise significantly in 1985 and subsequent years relative to the NGPA. Real GNP is down $1 billion in 1984, rising to $5 billion in 1986 and remaining at that differential through 1989. Although the timing is somewhat different, the cumulative impact on the economy of phased decontrol is very similar to that found under the Administration proposal.

Under continued controls, natural gas prices are below those found under the NGPA. By 1990, the wellhead price of natural gas is 7.4 percent below the NGPA, while the average residential price is down 4.5 percent. Residential consumption has increased by 1.3 percent in 1990 in response to the lower price of natural gas. The net effect of these factors is an economy with a slightly higher level of real GNP under continued controls, reflecting the positive effect on the economy of lessened inflationary pressures resulting from lower natural gas prices than under the NGPA. As can be seen in Table 9, real GNP under continued controls exceeds the level under the NGPA from 1985 to 1989, peaking at a difference of $4 billion in 1987. By 1990, however, there is no difference in the level of the economy relative to the NGPA.

While no formal analysis has been done of alternative monetary policy regimes accompanying the alternate scenarios, it can safely be assumed that suppressing monetary accommodation of gas price increases would accentuate real GNP losses due to higher gas prices under phased decontrol, while curbing inflation. Conversely, if a less stringent monetary policy were assumed under continued controls, GNP growth would be even higher, but at a cost of increased inflation.

Supplemental Energy Import Impacts

The preceding section discussed the impacts of alternative natural gas scenarios on the economy, assuming that no changes took place outside the natural gas market except those induced by price changes. In particular, "supplemental" sources of energy, which make up the difference between domestic natural gas production and consumption, were assumed to originate entirely within the natural gas market. In this section, supplemental sources are assumed to consist entirely of oil and gas imports. Such an assumption, which could be realized by increased gas imports from Canada and Mexico, is worth examining principally because of the potentially large impact on the general economy from significant changes in import levels. In the analysis above, differences in demand for supplemental sources between the NGPA, the Administration proposal, and phased decontrol were not large enough to significantly affect macroeconomic outcomes. However, in the case of the macroeconomic comparison between continued controls and the NGPA, much larger differences exist between supplemental demands in the two cases.

As can be seen from Table 10 and Figure 16, the higher import bills that result when the additional imports assumption is introduced in the continued controls case have a depressing effect on the economy. As a result, real GNP differences between the controls and NGPA cases are reduced, and by 1990 the continued controls case is actually lower by $2 billion. Table 10 also shows the revised economic impacts of the Administration proposal and phased decontrol vis-a-vis the NGPA case, when adjustments for imports are made in the estimates.

Table 10. Comparison of Projected Levels of Real GNP Alternatives to the NGPA Reference Case, with Supplemental Energy Imports, 1981 to 1990
(Billion of Constant 1972 Dollars)

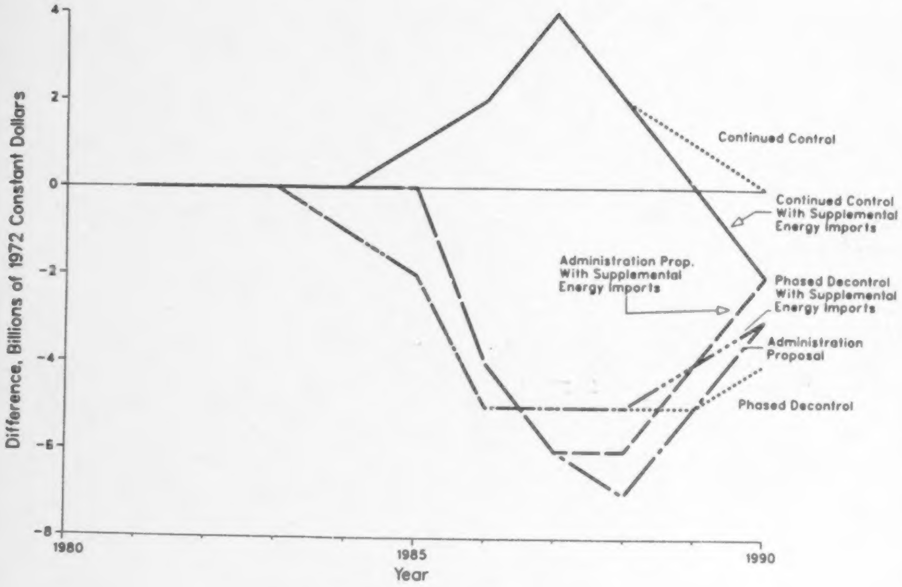
	Administration Proposal		Phased Decontrol		Continued Controls	
	Level	Difference	Level	Difference	Level	Difference
1981	1,503	0	1503	0	1,503	0
1982	1,476	0	1476	0	1,476	0
1983	1,505	0	1505	0	1,505	0
1984	1,577	0	1576	-1	1,577	0
1985	1,642	0	1640	-2	1,643	1
1986	1,690	-4	1689	-5	1,696	2
1987	1,740	-6	1741	-5	1,750	4
1988	1,786	-6	1787	-5	1,794	2
1989	1,837	-4	1837	-4	1,841	0
1990	1,896	-2	1895	-3	1,896	-2

Source: Simulation of DRI macroeconomic model.

Summary of Macroeconomic Impacts

In conclusion, the isolated effects on the economy of continuing gas price controls would appear to be positive, while those of the Administration proposal and phased decontrol appear negative, if only effects on the general inflation rate and aggregate demand are taken into account. Focusing on this single facet is misleading, however, since gas price controls also have impacts on imports, fiscal and monetary policy, and the overall efficiency of resource use within the economy. Monetary policy choices will affect the degree to which potentially more inflationary gas price paths are allowed to push up the general inflation rate; tightening or lack of accommodation in the money supply will lead to greater loss of output and employment in response to a gas price shock, but less inflationary effect as well. Sensitivity tests addressed only the "supplemental" energy issue, showing continued controls to result in lower real GNP over the long run if imports are assumed to rise to meet demands for supplemental energy due to gas price controls. Sensitivity tests did not address resource efficiency questions, but presumably the elimination of price controls results in gains in efficiency and hence greater economic growth.

Figure 16. Effects of Alternatives to the NGPA



Source: Simulation of DRI macroeconomic model.

Impact on Household Expenditures

This section discusses the impact of the different natural gas regulation cases on residential expenditures for natural gas. Average expenditures by households for natural gas are shown in Table 11 for the reference case for all households, and for households in the different census regions, Northeast, North Central, South and West. Expenditures for four different years, 1983, 1985, 1987, and 1990 are considered. All expenditures in the table and this discussion are in terms of constant 1982 dollars.

NGPA Reference Case

Under the NGPA reference case, average natural gas expenditures per household are projected to increase from $521 to $743 from 1983 to 1990. All regions of the country are projected to experience increases in expenditures. The annual rate of increase varies from 4.9 percent in the North Central region to 6.7 percent in the West. Generally, the relative levels of expenditure in the different regions are not affected by these differing growth rates. Expenditures in the Northeast region are highest at $642 and are slightly lower at $634 in the North Central region in 1983. The two regions continue to have the highest expenditures through 1990. The West has the lowest average expenditure level, $301 in 1983, which rises to $475 in 1990. Residential consumers in the West have historically paid low prices relative to the industrial sector. As prices rise over time, more of the burden is absorbed by the residential sector.

Administration Proposal

The pattern of expenditure changes in the Administration proposal case differs from the reference case. In 1983, average expenditures are lower in the Administration proposal case than in the reference case. However, by 1985, expenditures are larger in the Administration proposal case than in the reference case, and the difference is at maximum in 1987. Expenditures remain higher in 1990 in the Administration proposal case, although the difference is not as large as in 1987.

Regionally, the same pattern occurs. The largest increase in expenditures occurs between 1985 and 1987. Expenditures continue to increase through 1990, but the rate of increase is not as large. The West experiences the largest rise in expenditures in the Administration proposal case, a 7.4 percent annual rate of increase. The Northeast has the smallest increase, a 5.8 percent annual rate. The rates of increase in the North Central and South are 6.2 and 6.0 percent, respectively.

Phased Decontrol Case

Under phased decontrol, average expenditures for natural gas are higher than in the reference case, although the differences peak in 1985 and decline thereafter. At the peak, the differential between expenditures under phased decontrol and the NGPA is $70 per household, or about 12 percent of the reference case. The same general pattern

Table 11. Estimated Average Expenditures for Households Using Natural Gas Under the NGPA Reference Case and Policy Alternatives for Selected Years

		Average Household Expenditures (1982 Dollars)			
Region	Year	NGPA Reference	Administration Proposal	Phased Decontrol	Continued Controls
All Regions	1983	521	514	528	523
	1985	605	647	675	597
	1987	672	757	715	655
	1990	743	779	791	722
Northeast	1983	642	635	641	642
	1985	738	789	833	730
	1987	821	914	874	796
	1990	900	940	955	881
North Central	1983	634	625	646	640
	1985	742	805	832	744
	1987	825	932	874	812
	1990	893	950	951	869
South	1983	452	443	456	453
	1985	535	565	590	524
	1987	592	668	632	577
	1990	644	666	683	640
West	1983	301	300	310	302
	1985	350	364	384	330
	1987	392	447	420	376
	1990	475	495	509	441

Source: Calculations based on GAMS results.

holds in the different regions. The West experiences the largest percent increase in expenditures under phased decontrol, 64 percent, just as they gain the most from continued controls. In the rest of the country expenditures increase about 50 percent. By 1990, expenditures in all regions are 6 to 7 percent highter than in the reference case.

Continued Controls Case

In the continued controls case, average natural gas expenditures for all households nationally are slightly lower than in the reference case in all years except 1983. The differences between the two cases are greatest in 1990, when average expenditures under continued control are 2.8 percent less than under the reference case.

There are no major regional variations in expenditures; the patterns are similar to that for the Nation as a whole. The West benefits significantly from continued controls since household expenditures rise most rapidly there under the NGPA. In contrast, the South, which consumes substantial quantities of intrastate gas, and where slower growth in expenditures is projected, benefits the least. In 1990, expenditures in the South are 0.6 percent lower than in the NGPA reference case, the smallest difference among all regions.

7. SUMMARY

The purpose of this report has been to analyze the natural gas market through 1990 and to examine alternatives to the NGPA. Under current law, the natural gas market will go through a significant transition in the 1980's. The significant wellhead decontrol scheduled for 1985 will create a market quite unlike any observed in the past. Issues such as prudent contracting, when the wellhead market is tight, are raising serious questions. For example, can pipelines properly represent distributors and subsequently consumers in a deregulated wellhead market? Under current tariff structures the price of gas is unspecified in most downstream contracts (pipeline-to-pipeline or pipeline-to-distributor). Current downstream tariffs may not make sense in a deregulated wellhead market.

As a fuel, natural gas is unique in that it competes directly against fuels in all sectors except in transportation. Due to the transportation system and regulations, gas markets are regionally separated. The future of gas markets is difficult to analyze because there is no simple model that adequately represents the entire natural gas market.

In order to examine the natural gas market in sufficient detail, a model was constructed which explicitly considered pipeline systems and their contracts, the process of bidding for reserves, and the tariff structure of downstream markets. Using this model, the NGPA and three representative legislative scenarios were examined.

At the wellhead, the NGPA permits an artificially high price to be paid for new gas because the price controls, i.e., artificially low prices, remain on a considerable amount of old gas. Since uneven "cushions" of old gas exist among pipelines, a bidding disparity exists. The high marginal price for new gas, caused by the roll-in capacity created by price ceilings, encourages the early discovery and development of new reserves hastening depletion of the resource base. By 1990, pipeline purchasers of new gas will be paying more and getting less than under either phased decontrol or the Administration proposal. Because markets are segregated and the cushion is unevenly distributed, gas is allocated inefficiently to end-users. Due to the high depletion of the reserve base in the 1980's and the depletion of the low-price controlled gas, the delivered price to consumers could be very high in the 1990's under current law.

The Administration proposal creates the potential for a dramatic change in the natural gas market infrastructure which generates considerable uncertainty in the direction which the market will take. Under the Administration proposal, prices are generally higher than under the NGPA, but lower than under phased decontrol, and the market is able to respond better to market conditions. Since there are more volatile pricing clauses in the interstate market, that market obtains more relief compared to the intrastate market under phased decontrol. However, in the Administration proposal, average wellhead price disparities are essentially eliminated.

Under phased decontrol, production is lower because higher prices create demand conservation. Resources are also conserved for the post-1990 period. However, since most long-term fixed price contracts are in the intrastate market and most of the volatile indefinite escalator clause contracts are in the interstate market, the bidding disparity problem shifts and places the interstate systems at a disadvantage.

Continued controls put the Federal government in the position of acting as a cartel manager for the purchasers or a discriminating monopsonist. That is, the Federal government through the NGPA and the Commission (FERC) sets incentive prices based on cost and risk to elicit supply. Because of "regulatory lag" and the difficulty in properly setting costs, this situation raises the probability of shortages in the gas market. In the current analysis, supply must be supplemented or demand curtailed.

Under continued controls, new gas contract prices with the exception of Section 107 are capped by price ceilings. This restraint causes a misallocation of exploration capital toward the decontrolled gas, and the less expensive resources are not being developed first. Low average wellhead prices, due to price controls, stimulate higher production, which further depletes reserves. Additionally, these lower controlled prices stimulate consumption and create shortages, which must be accommodated by additional supply or curtailments.

The effect of any of the cases on the GNP or Consumer Price Index is considerably less than 1 percent. Therefore, broad conclusions about effects are hard to make. Under the continued controls case, the GNP improves relative to the NGPA case, but by the late 1980's the increased demand for supplemental energy imports makes the economy worse off.

The alternative scenarios analyzed represent very different alternatives to an acknowledged problem, the natural gas market under the NGPA. Continued controls appear to postpone facing the problem until the 1990's. Phased decontrol is an uninviting solution in the short run, but by 1990 the market is in much better condition. The Administration proposal allows the market to adjust to events more quickly and results in generally lower prices than under phased decontrol. By 1990, under the Administration case, the average wellhead price and the average delivered end-use prices are higher than under the NGPA, but the new contract price is lower and the reserves to production ratio is higher than under the NGPA.

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GLOSSARY

AGA: American Gas Association.

Allowables: The maximum rate of production from a well or group of wells that is allowed by a particular State or governing body. The rate is set by rules which vary among the various States or governing bodies.

AEO: Annual Energy Outlook (see Reference 9).

ARC: Annual Report to Congress (see Reference 65).

British Thermal Unit (Btu): The amount of heat required to raise the temperature of 1 pound of water by 1° Fahrenheit.

Ceiling Price: The maximum price a producer is allowed to collect under the Natural Gas Policy Act.

Consumption: The amount of natural gas consumed in the form in which it is acquired by the user. Unless otherwise specified, consumption refers to end-user consumption that does not include fuel used in production (lease and plant) and transportation (pipeline fuel).

Contract Pricing Provisions

1. Definite Price Escalators: Provisions that provide for either a fixed dollar price increase or a set percentage price increase on a periodic basis.

2. Indefinite Price Escalators: Provisions that allow for a future price increase which cannot be determined at the present time. One or more of the following clauses may be specified:

    a. Highest Allowed Regulated Rate Clause: This clause permits an increase in the contract rate above any fixed rate provision in the event that the regulated ceiling price, maximum lawful price, or area rate price, is raised by the governing authority. These clauses vary in the source cited as governing authority.

    b. Deregulation Clause: Many contracts currently governed by regulatory price ceilings specifically provide a process to reset the price of gas should price controls and regulatory authority cease. Some provisions which may be contained in a deregulation clause are listed below.

        - Price redetermination may be "equal to," "selected by the seller," or the "highest of" one or a combination of factors such as:

            - Btu-equivalent price of No. 2 or No. 6 fuel oil (oil parity), or another commodity.

            - Average price of two or three top contracts in the same producing area (most-favored-nation).

- Prices may be renegotiated where certain factors, such as the highest price currently being paid in the area, are considered but not specifically designated as the new price.
- A minimum price provision states that the redetermined rate will not be lower than a specified rate.

3. Buyer Protection Clauses: This category includes any option which permits the buyer to reduce the price below the redetermined price. One of the most common provisions allows the pipeline to request a redetermination if the price paid by the pipeline is disallowed by the Commission in ratemaking decisions. Normally, the price will then fall to a price the pipeline is allowed to recover. Other escape clauses, called "market-out," deal with the marketability of the gas or the economic conditions regarding sale of gas in certain locations. The following types of actions are included in this category.

   a. The buyer may elect not to pay the determined price if it is in excess of other contract price provisions. The seller may then cancel the contract or charge rates according to other contract provisions.

   b. If the buyer determines that the gas is not marketable at the redetermined price, he can notify the seller of an acceptable price. The seller can either accept the new price, cancel the contract, or solicit third-party offers. If the seller solicits and receives a third-party offer that is higher than the price the buyer specifies, the seller may give the buyer the option of meeting this offer and continuing the contract at that rate (buyer right of first refusal).

   c. If parties cannot agree on a negotiated price within 90 days after deregulation, the gas subject to renegotiation may be released from the contract.

   d. The contract may contain a maximum price which specifically states that the redetermined price will not go above a specified rate.

Cost of Service: The summation of the following items:

Operating Expenses
Depreciation, Depletion, and Amortization
Taxes -- Federal Income
Taxes -- State Income
Taxes -- Other Return on Rate Base

Gross revenues from gas operations are compared with the total cost of service to determine whether the revenues are excessive or deficient. (Cost-of-service studies, in which the above elements are considered, constitute an important tool or guide in determining just and reasonable rates.)

Cost of Service Tariff: A tariff that specifies that a natural gas company (seller) shall be reimbursed for his cost of service, including a specified rate of return on the rate base, as distinguished from the usual tariff which specifies sales volumes.

DAS: Demand Analysis System (see Reference 16).

Day Rate, Daywork Contract: A type of agreement between a drilling company and an operator in which a drilling rig and crew are contracted for a set fee per day. Any drilling difficulties, therefore, extend the time for drilling, thereby increasing costs.

EIA: Energy Information Administration.

FERC: Federal Energy Regulatory Commission.

Fly-up: A sudden increase in the natural gas wellhead price as the gas is no longer regulated; and in contracts with deregulation clauses, gas prices are determined by contract terms, such as favored-nation and oil parity clauses.

Footage Contract: A type of agreement between a drilling company and an operator in which the contractor agrees to drill a well to a certain depth for a fixed fee per foot. Any additional costs incurred due to drilling difficulties are absorbed by the contractor.

GAMS: Gas Analysis Modeling System; an EIA gas market analysis model which uses PROLOG as the supply input (see Reference 8).

Interstate Gas: Natural gas that is committed to interstate commerce and hence is subject to Federal controls under the Natural Gas Act.

Intrastate Gas: Natural gas that is both produced and consumed within the same State. (Before the NGPA, intrastate gas was not regulated by the Federal government.)

Lagged Quantity Elasticity Coefficient: This coefficient expresses the relationship between the percentage change in consumption during this period with respect to the percentage change in consumption in the previous time period.

Loss and Unaccounted For Gas: Actual natural gas losses due to leaks or the merging of new pipelines, customers coming on or leaving the system, meter breakdowns resulting in estimated billing, etc.

Lower-48 States: The land mass and adjacent outer continental shelf of the contiguous 48 States.

Market-Out Clauses: See Buyer Protection Clauses under Contract Pricing Provisions.

MEFS: Mid-Range Energy Forecasting System (see Reference 18).

MER: *Monthly Energy Review* (see Reference 4).

Monopsony: A market situation in which there is one buyer and many sellers.

Natural Gas Production: For this study, this is defined as marketed production: Gross withdrawals of natural gas from gas and oil wells less gas used for repressuring, nonhydrocarbon gases removed, and quantities vented and flared.

NGA: *Natural Gas Annual* (see Reference 32).

OCS: Outer Continental Shelf.

Off-system Sales: Natural gas sales made by pipelines to new customers in order to dispose of surplus gas that the pipelines' traditional markets cannot take.

Operator: The person or firm responsible for the day-to-day operation of a plant or facility.

Pipegate: The point of a gas purchase between a producer and first purchaser. The quantity purchased is usually less than wellhead production primarily due to the removal of lease and plant fuel. The price is usually higher due to gathering and processing charges.

PGA: Purchased Gas Adjustment (see References 1 and 3).

Price Elasticity Coefficient: A number that represents the percentage change in quantity of natural gas purchased with respect to a percentage change in price [e.g., if the price elasticity is equal to -0.4 and the price of natural gas to an end-use consumer were to increase by 20 percent, then the amount of natural gas purchased by this consumer would be expected to decline by 8 percent (i.e., -0.4x20% = -8%)].

PROLOG: Production of Onshore Lower-48 Oil and Gas Model, an EIA Supply Model (see Reference 6).

Purchased Gas Adjustment (PGA) Filings: Filings submitted by major interstate pipeline companies to the Federal Energy Regulatory Commission. These submissions allow the companies to recover the difference between their anticipated actual purchase costs for natural gas and the costs reflected in their current rate structure.

Reserves: The estimated quantities of natural gas which analysis of geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (proved reserves).

Reserves-to-Production (R/P) Ratio: This ratio is the value obtained by dividing current reserves by current production.

Take-or-Pay: Amount of gas required to be taken and paid for, even if not taken. Some percentages are based on minimum daily quantities, annual quantities, or minimum contract quantities. Take-or-pay quantities may change over time under initial provisions of the contract or may be changed in an amendment to the contract.

UGR: Unconventional Gas Recovery.

Unconventional Gas: Natural gas resources characterized by the geologic environment, including tight gas reservoirs, Devonian shale, coal seams, and geopressurized brine.

Wellhead: The point at which natural gas is transferred from the well to pipeline or other non-well facility. This term is used in referring to "wellhead price," which is the price producers of natural gas receive.

World Oil Price: Weighted average acquisition cost of imported oil of refiners worldwide.

Appendix A

MODEL METHODOLOGY

Overview

The natural gas market consists of four agent groups that interact with each other. They are:

- Producers: individuals and companies that search for new supplies of natural gas and sell gas to pipelines and end-users for consumption in their own operations.

- Pipeline Companies: firms that purchase supplies of gas at the wellhead, transport gas for resale to other pipeline companies to distributors or directly to consumers. These companies also consume gas as a pipeline fuel.

- Distributors: privately or publicly owned firms that purchase supplies of gas from pipelines and sell it to end-users for consumption in their own operations.

- Consumers: commercial establishments, industrial firms, electric utilities and residential dwellings that require natural gas for use as space and process heat, chemical feedstock, and boiler fuel to raise steam. (Some consumers, referred to as direct sale purchasers, purchase gas directly from producers.)

While the EIA has, in the past, produced projected estimates of the production, consumption and price of natural gas, the approach used to provide such estimates was not detailed enough to address important questions about the natural gas market. Accordingly, the EIA developed a new approach that provides a more appropriate method for representing the behavior of the above agent groups and assessing the detailed effects of deregulation and associated impacts. Based upon this new approach, a modeling system was developed, referred to in this report as the Gas Analysis Modeling System (GAMS), that spans all aspects of the natural gas market as shown in Figure A1.

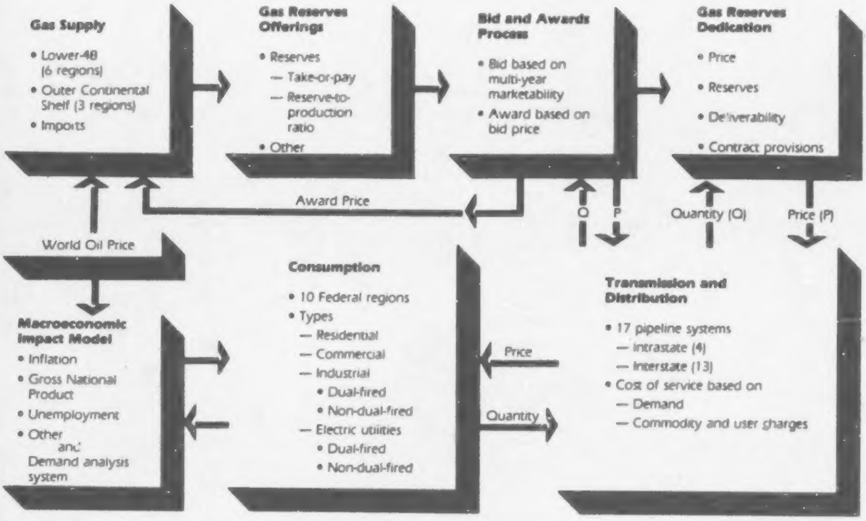
Producers, disaggregated on a regional basis, undertake drilling activities involving the development and exploration of crude oil (and associated-dissolved gas) and nonassociated gas (and lease condensate). Drilling activity levels are based upon expected profitability and capital resources. The profitability of each type of drilling activity is represented by the net present value of projected revenues and expenditures of each activity. The availability of rigs and other equipment to producers is determined by past and current revenues (net of excise taxes) at the wellhead from crude oil and natural gas production.

Every year, each type of regional activity competes for available rigs on the basis of relative profitability of prospective drilling efforts. Based upon the yields associated with finding rates, producers offer natural gas reserves (net of lease and plant fuel) to pipeline companies and other purchasers. Additional gas supplies are available from imports and synthetic natural gas.

Through a computerized simulation of future needs, pipeline companies and direct purchasers bid for reserves offered by the producers. The bid price is based upon the estimated production schedule and price of currently dedicated reserves and the estimated maximum amount and price of gas that can be marketed over the next several years. Reserves are awarded to the bidders on the basis of bid price. For price ceiling gas for which bidders are willing to bid above the ceiling, reserves are awarded according to historical market shares modified by bid prices.

Transmission and distribution of gas are simulated in a network representation of 17 pipeline system and about 4,000 aggregated markets. See Table A1 for a listing of companies included in each pipeline system. Each year, pipeline companies assess supply availability and customer demand on a seasonal basis and make decisions

Figure A1. Operational Data Flow of the EIA Gas Analysis Modeling System (GAMS)[a]


Gas Supply
• Lower-48 (6 regions)
• Outer Continental Shelf (3 regions)
• Imports
Gas Reserves Offerings
• Reserves
— Take-or-pay
— Reserve-to-production ratio
• Other
Bid and Awards Process
• Bid based on multi-year marketability
• Award based on bid price
Gas Reserves Dedication
• Price
• Reserves
• Deliverability
• Contract provisions
Award Price
Q
P
Quantity (Q)
Price (P)
World Oil Price
Macroeconomic Impact Model
• Inflation
• Gross National Product
• Unemployment
• Other
and
Demand analysis system
Consumption
• 10 Federal regions
• Types
— Residential
— Commercial
— Industrial
• Dual-fired
• Non-dual-fired
— Electric utilities
• Dual-fired
• Non-dual-fired
Price
Quantity
Transmission and Distribution
• 17 pipeline systems
— Intrastate (4)
— Interstate (13)
• Cost of service based on
— Demand
— Commodity and user charges

[a] GAMS consists of the modules shown; each box in the operational flow has an associated input, output, and operational methodology.

Table A1. United States Natural Gas Pipeline Systems and Their Components

Pipeline System	Interstate Pipeline Companies	Intrastate Regions
Lower Southeast Loop	El Paso Natural Gas Co.	--
Ohio Mid-Atlantic Line	Columbia Gas Transmission Corp.	--
Outer New England Feed	Tennessee Gas Pipeline Co. Tennessee Natural Gas Lines Inc. Alabama-Tennessee Natural Gas Co. East Tennessee Natural Gas Co.	--
Mid New England Feed	Texas Eastern Transmission Corp. Algonquin Gas Transmission Co. Consolidated Gas Supply Corp.	--
Upper Midwest Line	Natural Gas Pipeline Co. of America	--
Mississippi Line	United Gas Pipeline Co. Mississippi River Transmission Corp. Texas Gas Transmission Corp.	--
Southeast Coast Line	Transcontinental Gas Pipeline Corp.	--
Ozark-Arizona Run	Transwestern Pipeline Co. Cities Service Gas Co. Arkansas-Louisiana Gas Co.	--
General Southern Line	Florida Gas Transmission Co. Southern Natural Gas Co.	--
Great Lakes Supply	Michigan-Wisconsin Pipeline Co. Midwestern Gas Transmission Inc. Great Lakes Gas Transmission Co.	Illinois Indiana Michigan Minnesota Wisconsin
Upper Plains to Coast	Northwest Pipeline Corp. Colorado Interstate Mountain Fuel Supply Co. Kansas-Nebraska Natural Gas Co. Montana-Dakota Utilities	Colorado Montana North Dakota South Dakota Utah Wyoming
Lower Midwest Feed	Panhandle Eastern Pipeline Co. Trunkline Gas Co. Northern Natural Gas Co.	--

Table A1. United States Natural Gas Pipeline Systems and Their Components (continued)

Pipeline System	Interstate Pipeline Companies	Intrastate Regions
Intrastate Appalachia	National Fuel Gas Supply Corp.	Connecticut District of Columbia Delaware Florida Georgia Kentucky Maine Maryland Massachusetts New Hampshire New Jersey New York North Carolina Ohio Pennsylvania Rhode Island South Carolina Tennessee Vermont Virginia West Virginia
Intrastate Far West	Pacific Gas Transmission Co.	Arizona California Idaho Nevada Oregon Washington
Intrastate Texas-New Mexico	--	Texas New Mexico
Intrastate Oklahoma-Kansas	--	Iowa Kansas Missouri Nebraska Oklahoma
Intrastate Louisiana-Arkansas	--	Alabama Arkansas Louisiana Mississippi

aimed at marketing the maximal quantity of gas possible. The decisions are based primarily on producer prices, take-or-pay commitments in existing contracts, and estimated market demands. Once the gas is purchased, it is delivered to distributors (reduced by transmission losses), with demand and commodity tariffs added to the average purchase price. Prices for delivered gas include the distributors' commodity costs, the distributors' markups (which account for various operating, transmission, and storage costs plus the distributor-permitted return on investment), and demand ("hookup") charges.

Distributors deliver gas to six classes of end-use consumers: residential, commercial, electric utility (with and without alternative fuels capability), and industrial (with and without alternative fuels capability) consumers. Distributors assess demand, commodity, and user charges for each type of customer.

Estimated demand for gas is based upon historical patterns of consumption and the physical ability to switch to an alternative fuel. Response to price changes is assumed to have both an immediate effect and a lagged effect on consumption which may vary regionally and by end-user type.

Removal of price ceilings on natural gas has two effects. First, purchasers of new gas reserves are allowed to bid and pay a price based on their estimates of marketability. Second, prices for production from currently dedicated reserves are based on escalator terms in the contract.

Natural Gas Supplies

The natural gas supply forecasts used in this report are obtained from two sources: the Production of Onshore Lower-48 Oil and Gas (PROLOG) Model [1], and the Outer Continental Shelf (OCS) Model [2]. Supply from Alaska is omitted from this analysis as discussed in Appendix B. The availability of synthetic and imported gas is an exogenous estimate.

Onshore Lower-48 Reserve Additions for Natural Gas from Conventional Sources

PROLOG forecasts annual oil and natural gas exploration and production activities for the six onshore regions of the Lower-48 States depicted in Figure A2. The primary activities of these regions are exploratory and developmental drilling. Forecast values include the reserve additions from exploratory drilling. Within drilling resource constraints, the model chooses drilling activities that result in reserve additions and production on the basis of discounted present value.

Drilling activities are differentiated by category. Oil and natural gas drilling are evaluated separately for each subclass of drilling. Exploratory and developmental drilling are treated separately, with developmental drilling further subdivided by the type of reserves to be developed. The major distinction in the nature of drilling within the model lies between exploration and development: exploration yields new additions to the stock of known reserves; development determines the rate of production from the stock of known reserves.

For each year of the forecast horizon, the data transferred from PROLOG to GAMS constitute a set of projected reserve additions and projected production profiles. Production profiles generated by PROLOG are used to determine the maximum available production and to adjust the maximum available production capacity based upon subsequent developmental drilling. Annual production forecasts are determined from a range of production options based upon maximum production capacity, take-or-pay options, and the derived demands of the pipelines and distribution companies.

Figure A3 presents a schematic depiction of the PROLOG model, which steps through time in yearly intervals. For both oil and gas in each region, a range of possible footage for exploratory drilling is determined, based upon historical growth rates. The range dictates the maximum and minimum amounts of exploratory drilling that may be conducted in each region for either oil or gas. The range is divided into smaller units of drilling footage called steps. The model employs the footage level and the finding rate within each step of drilling to compute the resulting reserves added. The discounted cash flow is then calculated to evaluate the present value of these reserve additions on the basis of a generic production profile.

Developmental drilling is handled in essentially the same fashion as exploratory drilling. The range of drilling is set for both oil and gas in each region for all types of development. The range is divided into steps. For each step, the existing production profile is modified to reflect the effect of further development. Based on the new production profile, the net present value of the additional development drilling is computed using the discounted cash flow technique.

Next, net present value per foot drilled of each proposed activity is considered within a constraint on available rigs, bounds on exploratory or developmental drilling for each fuel within a region, and a short-run drilling cost curve. The choice of drilling activities is accomplished on a merit order basis by a linear program. This cycle is repeated for each year of the forecast horizon.

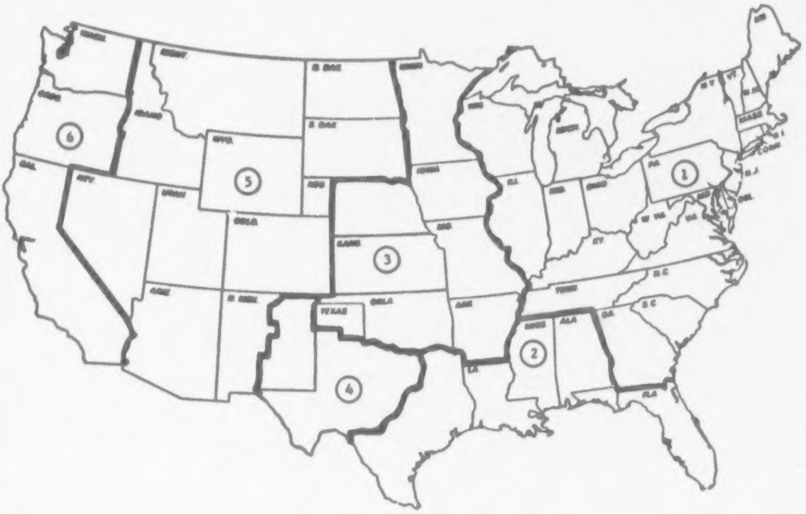
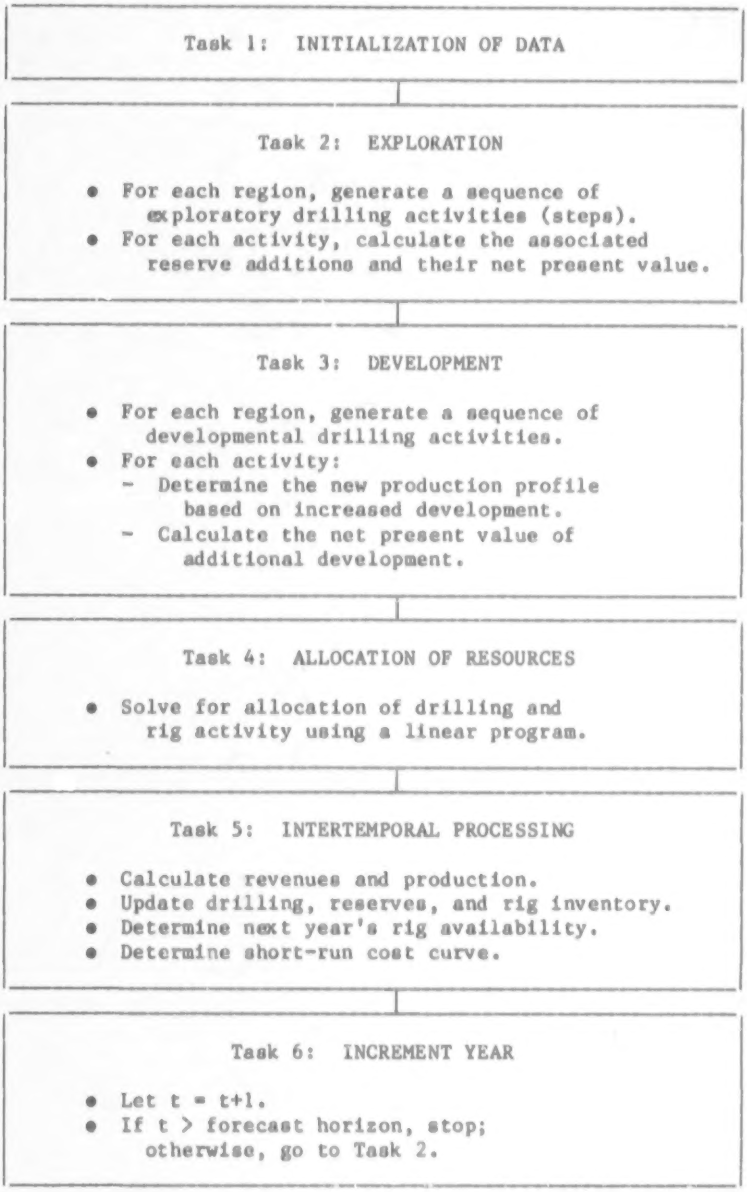


Figure A2. Natural Gas Supply Regions



Task 1: INITIALIZATION OF DATA

Task 2: EXPLORATION

- For each region, generate a sequence of exploratory drilling activities (steps).
- For each activity, calculate the associated reserve additions and their net present value.

Task 3: DEVELOPMENT

- For each region, generate a sequence of developmental drilling activities.
- For each activity:
  - Determine the new production profile based on increased development.
  - Calculate the net present value of additional development.

Task 4: ALLOCATION OF RESOURCES

- Solve for allocation of drilling and rig activity using a linear program.

Task 5: INTERTEMPORAL PROCESSING

- Calculate revenues and production.
- Update drilling, reserves, and rig inventory.
- Determine next year's rig availability.
- Determine short-run cost curve.

Task 6: INCREMENT YEAR

- Let t = t+1.
- If t > forecast horizon, stop; otherwise, go to Task 2.

Figure A3. Schematic representation of the PROLOG algorithm.

The rig constraint, that is, the number of rigs and other necessary equipment available for drilling, is based upon historical relationships among wellhead revenues for oil and gas, drilling expenditures, and rig depreciation. The short-run drilling cost curve represents the change in the cost of drilling due to yearly fluctuations in drilling levels based upon historical information.

Projections of unconventional gas, or gas from tight formation gas reservoirs, are based upon a study by the National Petroleum Council (NPC) [3]. (See Appendix B, Assumptions.)

Outer Continental Shelf (OCS) Projections

The lag time for production from new OCS leases is 5 years or more as of the date of lease. Given the existence of the Natural Gas Policy Act (NGPA) of 1978, ceiling prices for new gas are known in constant dollars for the first half of the 1980's. Any divergence between anticipated and realized prices for the latter part of this decade can affect the behavior only in 1990, which is the last year of the forecast horizon covered by this report.

OCS forecasts are generated by the OCS Model using available data on economics, offshore drilling and production, resource base, and the institutional framework (see OCS model documentation [2]). Economic data include the costs for all phases of the production process and the tax structure. The tax structure is incorporated in order to be able to account for the tax reductions generated by business expenses. The resource base is represented by a stochastic depiction of all known structures in the OCS regions. The uncertainty surrounding the resource base is dealt with by employing a Monte Carlo technique using a probabilistic representation of the resource base. The institutional framework consists mainly of the most recently announced leasing schedule from the Department of the Interior.

The projected array of new field reserve additions from the OCS Model allows production from these reserves to begin in 1986 due to the assumed 5-year lag between initial activities in a region and the beginning of production. This presents a problem for the Gulf of Mexico, but not for the Atlantic or Pacific regions, where production from these reserve additions is not initiated until the end of the decade. This gap in the forecast from 1981 through 1985 for the Gulf of Mexico is filled in the following way.

The base case forecast contains the actual 1981 level of reserve additions for the Gulf of Mexico (GOM). The methodology description for the OCS Model (OCSM) includes a procedure to develop reserve additions based on acreage leased as of 1980. These figures are used for 1982 through 1985. The completed drilling schedule requires 3 years, causing some overlap between the offline projections and the OCSM forecasts. The two sets of figures are summed for each year; one set represents reserves from acreage leased as of 1980, and the other represents reserves from new areas.

Natural Gas Reserves

The Gas Reserves Supply Table (GRST) is an accounting scheme for available supplies, both dedicated and projected, and for prices on an annual basis. PROLOG and OCSM provide projected reserve additions throughout the remaining model time horizon. These reserve additions are adjusted annually. The price escalator routine discussed below updates the prices each year. This information is used by the Bid and Award Model to determine the award price for new supplies of gas and by GAMS to determine annual production based on supply requirements. The GRST consists of "reserve blocks," with several items of information required for the transactions between producers and first purchasers of natural gas.

The primary item in a "reserve block" is the reserves available for sale, net of lease and plant fuel, for the current year for a particular pipeline system. About 7.5 percent of the wellhead production is "lost" to lease and plant fuel, which is an unavoidable in-kind cost incurred in the dry natural gas production process. As a well-known and therefore anticipated drain from production, the negotiations for purchases of pipeline quality gas must account for this loss during the production process. Generally, purchase negotiations are agreements for gas net of lease and plant fuel use. This procedure enables the accounting of all costs. First purchasers of natural gas contract for quantities of gas that are to be used for satisfying the demands of their customers. Information is included on the location and dedication status of the reserves. This consists of a region code for one of the six onshore regions or three offshore regions and, if dedicated, the pipeline system designation. Other information in a reserve block consists of the NGPA Title I Section and subcategory and its expected current year purchase price. Gathering charges and taxes are an additional cost to the first purchaser and are added to the wellhead price.

The three significant points in time for the gas reserve block are specified: (1) the first year of production, (2) the first year of peak production, and (3) the last year of peak production. Further, information is provided that enables calculation of the rate of decline from peak production. This production profile is essential to the potential purchaser's scheduling of gas flows along a fixed capacity network and planning for future needs.

The final item in a reserve block is pipeline take-or-pay requirements. This item specifies the percentage of maximum contract volume for which a purchaser must pay, regardless of whether the gas is taken. The lower the take-or-pay value, the more flexibility a purchaser has in planning operations.

Contract Price Escalation

Average wellhead prices of reserves are provided by pipeline group, NGPA section, and interstate or intrastate market for contracts existing in 1980 and for new contracts written in 1981 or later.

The pipeline groupings consist of the following pipeline systems.

Grouping	GAMS Pipeline System
Northeast	Ohio Mid-Atlantic Line Outer New England Feed Mid New England Feed South East Coast Line
West	Lower Southeast Loop Ozark Arizona Run
Midwest	Great Lakes Supply Lower Midwest Feed Upper Midwest Feed
Mountain	Upper Plains to Coast
South	Mississippi Line General Southern Line
Appalachia	Intrastate Appalachia
Far West	Intrastate Far West
Texas-New Mexico	Intrastate Texas/New Mexico
Oklahoma-Kansas	Interstate Oklahoma/Kansas
Louisiana-Arkansas	Intrastate Louisiana/Arkansas

The wellhead prices are escalated over time using assumptions of contract price escalator clauses. Five types of contract clauses were used in developing these averages. Table A2 describes the various price escalator categories. The categories are mutually exclusive and collectively exhaustive. For example, a contract may contain a highest allowed regulated rate and an oil-parity clause which will take effect upon deregulation. Because contracts contain these multiple pricing provisions, a hierarchy was developed, with the more volatile pricing clauses taking precedence over the others. These are listed in the order of precedence in Table A2.

Gas Supply Bid and Award

After new reserves are discovered, the producers set out to find buyers, who bid for gas that has been discovered. This process is modeled by the Bid and Award Component. The supply interface with the Bid and Award Component consists of a communications loop between producers and buyers. PROLOG passes the relevant supply information to the Bid and Award Component in the Gas Reserves Supply Table format. The Bid and Award Component subsequently returns a market-clearing price (the award price) to PROLOG for use in projecting gas discoveries and developments of subsequent periods. The process simulates the market transactions for natural gas.

Table A2. Price Escalator Categories

Category	Description
Deregulation Clause, Oil Parity with No Market-Out	A redetermination clause which specifies that the deregulated price will be tied to an oil-parity value, and no market-out provision is contained in the contract which would permit the purchaser to adjust the price or terminate purchases.
Deregulation Clause, Most-Favored-Nation Clause with No Market-Out	A redetermination clause which specifies that the deregulated price will be tied to the average of other contracts and no market-out provision is contained in the contract. For this category, those contracts which had a most-favored-nation clause but were included in the oil-parity category above were excluded from this category.
All Other Deregulation Clauses	This includes any contract with a deregulation clause that was not included in the above deregulation categories. This also includes contracts with oil-parity and/or most-favored-nation clauses that contain market-out options.
Highest Allowed Regulated Rate	An indefinite escalator clause which specifies that gas will be priced at highest allowable rate.
Definite Only	Fixed price contract or a contract with a specific price escalation path.

This approach is a break from the more traditional modeling approach, which views pipelines as purchasers of "spot-market" production in a given time period. Purchases of produced gas not under long-term contract are very limited. Pipelines and other first purchasers generally contract for the receipt of gas volumes over time. In essence, the pipelines contract for newly discovered reserves to be purchased over time according to specified contract terms. The long-term nature of such contracts requires the consideration of expectations in the transaction. In addition to the scheduling of gas flows along a fixed capacity network, the negotiations for the purchase require the anticipation of future discoveries. The expected availability of new supplies should and does affect the willingness of buyers to pay a particular price. In turn, the most recent price established for new reserve additions affects the price anticipated by producers over ensuing time periods.

The PROLOG component is executed to generate the Gas Reserves Supply Table, which lists discoveries of natural gas deposits over time, along with associated information characterizing these deposits. The PROLOG forecast is based upon an expected path for the price of newly discovered gas. In time periods past, the ceiling prices of new gas conformed to the formulas of the NGPA. Given the initial set of expected new gas prices, PROLOG generates a schedule of reserve additions. The information is used in the Bid and Award Module to determine the award price for gas. The new award price for gas is then used to modify the previous expected prices for new gas. The new price enters PROLOG for the next year, and the process continues for the specified time horizon.

This process approximates the market mechanism in which reserves are committed under contract according to a schedule of production and prices. Long-term contracts are negotiated with consideration of the buyers' and sellers' expectations concerning future supplies and demand. The prices realized from a current time period affect the expected price path. This new price path then influences behavior in the subsequent time period, and so the process continues. In addition to explicit approximation of the actual supply market transactions, GAMS does not allow decision makers to act with perfect knowledge. All behavior is based upon expectations that may or may not be realized. The differences between expected and realized values allow the model to represent the adjustment process, which all agents in the market must follow in the face of changing conditions.

The bidding for, and acquisition of, natural gas supply are handled within the GAMS framework by the Bidding and Award Module. The bidding module evaluates, from the point of view of each pipeline system, the current dedicated reserves and future anticipated needs. Each pipeline system makes a bid for a portion of the current year's newly discovered reserves. A bid price is the average price that a pipeline is willing to pay for new reserves. If the ceiling price of one category of gas were below this bid price, the price that the pipeline would be willing to pay for decontrolled gas would be correspondingly higher than the bid price; also, the overall average price paid would be less than or equal to the bid price. Because the majority of new reserves in years past was price-controlled gas, the decontrol price may have been quite high. To prevent extremely high values, based solely on the system's ability (as opposed to its willingness) to pay, the decontrcl price is now capped at 130 percent of the projected price of No. 2 fuel oil. Thus, the awards routine evaluates bids from the producer's point of view and enters into contracts with pipeline systems for the current year's reserves based upon the bids of all pipeline systems.

The bidding routine uses a dynamic programming approach to determine a bid price for new gas reserves. The bid price is the decision variable. The quantity of reserves controlled by a pipeline system and the average price for production from the reserves are called "state variables" because these variables describe the state of the system at any point in time. The bid price determines an expected fraction of new reserves to be captured. The bidding routine establishes a series of bids based on different expected prices. The function that specifies the fraction of expected new reserves returns different values depending upon what the system expects the overall average acquisition price of new reserves to be. The higher this expected price, the lower the fraction of reserves will be for a given bid price. The awards routine uses the bids of each pipeline to establish an overall average price, the actual bid price, and the actual fraction of reserves allocated to each pipeline. In this way, it brings the quantity of new reserves demanded into line with the actual quantity of reserves available.

The awards routine uses the bid price and the desired quantities to allocate the gas reserves. After realigning the bid prices and desired quantities, the awards routine allocates the controlled reserves to each pipeline according to the actual fraction of existing reserves, and allocates decontrolled gas to each pipeline according to bid prices, with the higher bidders receiving proportionately more than the lower bidders. The decontrol price is the lower of 130 percent of the projected No. 2 fuel oil price and the average price the pipelines would be willing to pay for decontrolled gas based on rolled-in gas. The higher a pipeline system bids, the larger the share of newly discovered reserves it captures.

The bidding routine is based upon the assumption that a pipeline system, which bids for newly discovered reserves, seeks to maximize the amount of gas it can purchase and resell over the planning horizon. The lower it can keep the cost of purchased gas, the larger the share of the end-use market it captures. The bidding routine is executed for each pipeline system, independent of other pipeline systems. The decision variable is the price bid for newly offered gas reserves. The bid price determines the portion of new gas reserves awarded to a pipeline system and the average production price of new reserves. The price paid for new reserves will affect the price the pipeline system must charge its customers in future years. The pipeline system "rolls in" the price of new reserves; i.e., it passes an average gas production price on to its customers.

A pipeline system is assumed to be concerned with controlling the average price of all new gas reserves contracted for in a given year. Likewise, a pipeline system is concerned that gas be sold in bundles, such that the price of gas not be subject to changes in the control of the wellhead price; by selling gas in bundles, the average price of the bundle, including controlled gas, stays at the agreed price. Based upon the average bid price of all pipeline systems, the reserves available in the current year are awarded to a pipeline system contingent upon observing the following principles:

- The average price of new reserves must not exceed the average bid price.
- The quantity of reserves must not exceed the expected quantity.
- Reserves in price-controlled categories must be assigned using a market share formula that allocates shares based upon a prespecified percentage and the prices bid by pipeline systems.

The amount of gas resold in one year by a pipeline system is the minimum amount of gas that can be produced from reserves dedicated to the pipeline, and the amount of gas demanded by a pipeline system's gas consumers combined with net transactions with other pipeline systems and imports.

Natural Gas Transmission and Distribution

Transmission and distribution of natural gas are simulated by a network of nodes representing pipeline companies, distributors, and end-use markets, and links or "arcs" representing sales relationships. This network is divided into pipeline systems. A pipeline system is a prespecified group of purchasers that includes pipeline companies, distributors associated with pipelines, and markets acting as a single unit in their bidding for available reserves.

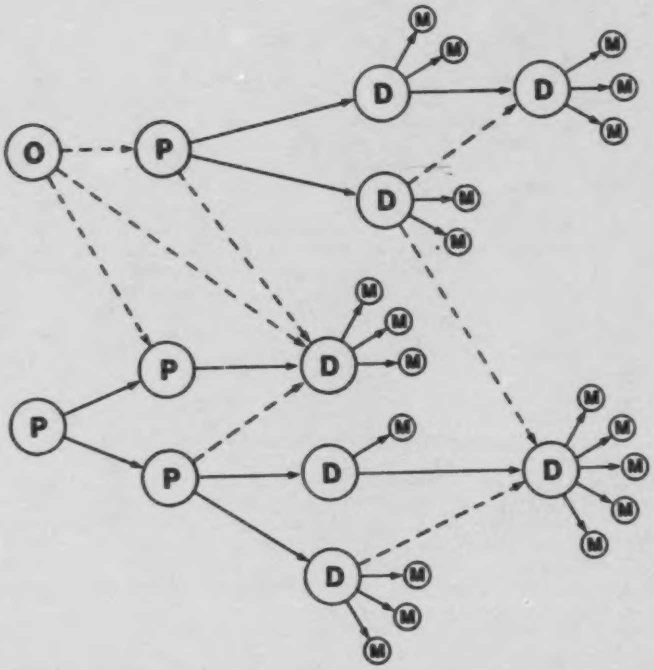
The network is divided into 17 pipeline systems, each of which represents a group of purchasers (or a pipeline system as in Table A1). These pipeline systems transmit gas to the end-user markets directly or indirectly from producers (that is, sales for resale) and from distributors that link the indirect market sales with the pipelines. Each node in the base network is in a single pipeline system. Each distributor in a system has one designated primary supplier, the pipeline or the distributor, identified by Form FERC-50 baseline data as the source of greatest domestic supply volume. All other supplies to the distributor are aggregated and treated thereafter as "committed."

The "primary supply" relationship is specified by an arc in the pipeline system and the supplier and customer nodes, i.e., the structure of a pipeline system is fixed by the initial data. Thus, an underlying assumption of the model is that the transmission and distribution system can be represented by classifying resale supply contracts involving distributors into two basic types, "committed" and "optional," such that all supplies that flow on "primary" or system arcs are optional, whereas those that flow on other or "secondary" arcs are take-or-pay. Figure A4 presents a sample two-pipeline system network. A distributor providing primary supply to another in a particular system may also furnish part of the aggregate take-or-pay supply to a distributor in the network of a different system.

For a pipeline system that has more than one pipeline, a pipeline system "root node" is created as a surrogate for aggregate producers (the "wellhead"). The root is defined as the primary bidder on behalf of other pipeline nodes in the pipeline system.

Links or "arcs" in these systems, as in the base network, represent gas supply relationships; they may also represent direct physical conduits, such as pipes, but not in all cases. Market nodes, which appear explicitly in the system, represent user sectors. A residential node, for instance, represents all of the residential customers of a particular distributor in a given state. Thus, a distributor may have up to six customers, representing (in curtailment priority order) the residential,

Figure A4. Diagram of a Sample Distribution Network with Two Pipeline Systems



Key: P, pipeline companies; D, distributors; O, all imports; M, market sectors; solid arrows, primary or system supply arcs; broken arrows, secondary or "committed" supply arcs.

commercial, electric utility, industrial, electric utility with dual fuel capability, and industrial with dual fuel capability sectors. The latter two are sometimes referred to as "fuel switchers" because they can readily use residual oil instead of gas, in response to price differences. Market sector nodes are each served by a single supplier.

The root node (or the single pipeline node in systems that have only one pipeline) is the system interface to the wellhead and is sometimes called the "pipegate." The intermediary distributor nodes are collectively called the "city gate," and the markets are called the "burner-tip."

The model first sets up initial conditions for the iterated annual operation of the market. That is, inconsistencies and omissions in the supporting data are reconciled to yield an overall consistent pattern of demands, prices, and flows, along with status of reserves, take-or-pay commitments, and storage requirements throughout the network.

At the start of each ensuing year, the status of reserves and currently available wellhead supply for each pipeline system is determined by query to the bid and awards model. Secondary flows and costs are combined and posted to pipeline system nodes. Node storage quantities for heating season withdrawal are assigned by reference to the difference between summer and winter demand in the previous year. Pipelines and distributors set tariff and demand rates based on estimates of current (forthcoming) year customer demand (derived from simple escalations of previous year demand). Finally, parameters for the calculation of demand are updated.

Thus the stage is set for clearance of the markets for each system in the summer, delivery of gas to customers and injection of storage gas, followed by winter (heating season) withdrawal from storage, market clearance and delivery of gas, after which annual market summary bookkeeping and reporting are done. A second interaction with the bid and award model occurs at this point, this time to report to that model drawdown of reserves in satisfaction of market demand.

At year end, prices and quantity flows are updated on the secondary arcs based mainly on the change in primary (system) prices for the year. Updating transmission tariffs (from pipelines) completes the determination of starting conditions for the next model year.

The direct interactions between pipeline systems can occur at the start of a year when secondary inflow to nodes is accumulated, because this committed supply will affect net system demand in the clearance of markets. Indirect interactions occur at the end of the year when the system prices affect secondary flow for the following year.

Network Construction

The Form FERC-50, "Alternate Fuel Demand Due to Natural Gas Deficiencies," is the major source of information that was used to create the gas market transmission and distribution network. FERC-50 was designed to collect the data necessary to support efforts pursuant to the Department of Energy's (DOE) responsibility for equitable allocation of natural gas and related products among all regions of the United States, all sectors of the natural gas industry, and all users. All interstate and intrastate pipeline companies, municipalities, and other suppliers of natural gas to end-users were required to complete the form. Completed FERC-50 forms provide the following information.

- volume of gas purchased from each source;
- nature of suppliers (interstate, intrastate, imports, or producer); and
- total volume of gas delivered monthly to end-use customers and number of customers by customer category (residential, commercial, industrial, electric utility, and other) and by State.

Monthly end-use sales by customer category were processed to determine load factors and heating season factors. Another data source used extensively was Form FERC-2, "Annual Report of Natural Gas Companies." Among other information, FERC-2 reported average prices of gas sold for resale to each company, and average prices of direct sales by pipelines to end-users, i.e., "Field and Main Line Industrial Sales," as well as distribution sales to other end-users.

The base network is a collection of points, or nodes, and links between nodes called arcs. The nodes represent natural market entities, such as pipeline companies, distributors, and conceptually, end-use market sectors. The arcs represent transitional or supply relationships between the entities.

As shown in Table A1, 38 pipeline companies (31 bearing the names of actual existing companies and 7 generic aggregates labeled "intrastate") are grouped into 17 pipeline systems. The initial set of 48 pipeline nodes consists of one node for each actual or aggregate pipeline company plus one for each multipipeline system.

Given this set of pipeline nodes, the network is augmented using data from the Form FERC-50 Supply File to identify other nodes, which are then added to the network. In the Supply File, every respondent (pipeline or distributor) identifies each source of supply by its 5-digit identification number and by gas volume. For each respondent, a node is generated and added to the node list (becoming a potential qualifying supply source in a subsequent pass) if one or more of its supply sources is currently listed. At present, two complete passes are made through the Supply File, creating and adding nodes according to the specified rule.[1]

After making two passes through the Supply File and adding appropriate nodes to the node list, a third pass is made to create the arcs of the network (see Figure A4 for a diagram of a sample two-pipeline distribution network). Typically, each respondent reports several supply sources. The arc generation procedure depends upon whether or not nodes exist which correspond to the respondent and to one or more sources on the node list. If there are nodes corresponding to both the respondent and the source on the node list, an arc is created with origin at the source node and destination at the respondent node. If the respondent node is on the list and the source node is not (i.e., the respondent has at least one source on the list and at least one source not on the list), an arc is then created with a base node origin and destination equal to the respondent node. When the State location of the respondent's end-use sales is later identified, the origin of this arc will become the generic intrastate pipeline which serves that State. If the respondent is not on the list, all supplies to that respondent are then aggregated and associated with an arc from the appropriate generic intrastate pipeline origin to a generic node in the State indicated by the leading two digits of the 5-digit identification number of the respondent.

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[1] After two passes, a cutoff was chosen. This rule is based upon past experiments in which 1,202 nodes (derived from the pipeline list shown in Table A1) were on the node list after two passes; no additional nodes were added beyond the fifth pass at which time 1,242 nodes were on the list, plus 224 nodes that would never have been added had additional passes been made. Those respondents that were not picked up during the first two passes through the FERC-50 Supply File are not explicitly represented in the network. Purchases and sales for these respondents are aggregated and associated with generic distributor nodes, one of which, at most, is created for each State during the development of the network. Distributors reporting sales of sufficient volume in more than one State are represented by several nodes according to market location.

After the Supply File is read, the FERC-50 End-Use Sales File is used to establish markets for each node in the network. Each FERC-50 respondent reports the following information for each State in which there were end-use sales: monthly and total volumes, and average number of customers by customer category, i.e., residential, commercial, industrial, electric utility, and "other." Sales reported as "other" include sales to public facilities, e.g., schools and hospitals. As each end-use sales record is read, the following data transformations are made:

- In the States of Maine, Connecticut, New Hampshire, and Vermont, all utility sales are aggregated with commercial sales. Local legislation in these States requires the burning of gas by electric utilities to be phased out. Any utility sales reported are assumed to have been commercial sales that were labeled erroneously.

- All "other" sales are aggregated with commercial sales and are not distinguished subsequently.

- Industrial and electric utility sales above a threshold volume, as reported on the FERC-50, are split into two markets, one of which has the capability of switching to alternate fuels.

The three data transformations described above lead to a maximum of six markets per State for each respondent: residential, commercial, electric utility, industrial, electric utilities with alternate fuel capability, and industrial with alternate fuel capability. The end-use markets are assumed to have priority in the order listed above, whereas residential customers are the last to be curtailed during supply shortages.

Another data item is storage capacity. Input to the network specifies the storage capacity available at pipelines and distributors. Gas stored in the summer and completely withdrawn in the winter is assumed to be used by distributors or pipelines in an attempt to balance seasonal flow. Therefore, market entities annually estimate current storage requirements as half of the difference between winter and summer demand of their customers in the previous year, adjusted for losses. (If, for example, in a previous year, summer and winter end-use sales of a pipeline had been 100 Mcf and 200 Mcf respectively, then, ignoring losses, storage of 50 Mcf in the summer and drawdown of 50 Mcf in the winter would lead to equal flows of 150 Mcf in both seasons, barring changes in demand.)

Market sector nodes carry preset parameters describing consumption patterns. These data were generated using FERC-50 monthly end-use sales data for the period April 1980 through March 1981. A "heating factor" and a "load factor" were calculated for each user category (residential, commercial, utility, industrial, and other) per FERC-50 respondent. The heating factors are used to represent seasonality of demand; the load factors are used in a rate-setting routine. The heating factor is defined as end-use sales to a market sector from October through March divided by the total end-use sales (April through March) to that market sector. Roughly speaking, the heating factor is the ratio of winter consumption to total consumption. The monthly load factor is the peak monthly end-use sales divided by the average monthly end-use sales during the reporting period April through March. A transformation from monthly load factors to daily load factors (multiplying by 1.5) is performed when the load factors are used for rate setting.

Prior to first-year simulation, adjustments are made to the initial ("base year") gas quantity flows and prices in the pipeline system networks in order to reconcile inconsistencies in baseline data from disparate sources and account for distribution losses and unrecorded sales or purchases.

For flows, a material balance or flow conservation condition is imposed on the activity for the year at each node. In this way, with transmission losses taken into account, total outflow is equal to total inflow, and flows in the direction of markets are all positive. ("Inflow" at root pipeline nodes is wellhead production and is assumed unrestricted for the base year; "outflow" at market nodes is consumption. No transfer of gas from markets is permitted in the simulation.)

The balances are achieved by allowing for market distribution losses up to 10 percent of deliveries and then, if necessary, by pro-rata increases in the recorded demand at the markets. (The values for transmission loss from pipelines are determined by the average mileage of transported gas in each pipeline zone on those supply arcs for which specific values have not been preset by input. These values are not altered in adjusting the base-year flow. In this process, corrections are made to the loss factors for delivery from distributors and their market nodes and are considered permanent. The adjusted market loss factors are fixed throughout the subsequent simulation.)

Tariffs

The (seasonal and annual) transaction prices in each pipeline system have three components: a purchase gas charge, a transmission or distribution tariff or "commodity" surcharge, and a fixed or "demand" charge. The commodity charge is the average "bottom line" price, i.e., a net acquisition cost per unit volume of all supplies to the seller, and is the same for all system customers of the seller. The surcharge (which, by convention, is labeled "transmission tariff" when the seller is a pipeline and "distribution tariff" when the seller is a distributor) represents recovery of the seller's operational expenses, permitted return on investment, transmission and storage losses, and "interzonal rate differentials"; thus, the surcharge varies among customers. The demand charge is a fixed charge, representing typically the cost of maintaining the capability of delivering estimated peak-day volume of gas to the buyer. Initial formulations for the markups are derived from baseline data by regression models and adjusted in the base year as described below. In subsequent years, they are increased by fixed inflation factors.

Markups for committed supply transactions are fixed fractions (currently 10 percent) of the purchase gas charge. Note that in a price path from the wellhead to the burner-tip, each reseller's acquisition cost is the average net cost per unit volume, i.e., adding committed supply and subtracting committed sales; the price paid at a market reflects all markups in the path.

Tariff Calibration

Several types of price data are used to make the network operational. For sales from interstate pipelines to distributors, prices are taken directly from the average annual prices reported by the pipelines in the Form FERC-2 for each recipient of "Sales for Resale." Should FERC-50 report a transaction that is not reported in FERC-2, the weighted average price of a pipeline's sales is used. For interstate pipeline direct sales, the base-year price is taken from the FERC-2 as the average annual price reported by State for "Field and Main Line Industrial Sales."

For direct sales by intrastate pipelines, prices are the "Resale Prices" reported in the 1980 Gas Facts [4]. According to a footnote in Gas Facts, State average prices are representative of city-gate prices. The reported prices are used directly in the following 12 States: Alabama, Arkansas, California, Kansas, Louisiana, Mississippi, New Mexico, Ohio, Oklahoma, Texas, West Virginia, and Wyoming. These States all have substantial intrastate markets that would be reflected in the reported prices. For all other States, the prices are averaged over the aforementioned 12 States and used for sales from generic intrastate pipelines to distributors.

The remaining resale prices are those for sales from one distributor to another. No source of price data on these transactions has yet been found. The procedure used to calculate prices for these sales follows. First, the network nodes are ordered so that if node A preceded node B, the longest path from a root node to node A would be shorter, i.e., it would have fewer arcs than the longest path from a root node to node B. Proceeding through the network ordered in this way, the prices on all arcs originating at node A can be calculated as the weighted average of the prices, which are paid for supplies by node A and increased by some markup. The markup currently used is 10 percent. Available data on sales from distributors to user markets consist of State averages by market sector from the 1981 Natural Gas Annual (NGA).

Price adjustment for the base-year networks reconciles State/market sector data from the Energy Information Administration's 1980 Natural Gas Annual, with prices compiled from pipeline reserve purchases.

Price adjustment is a two-stage process. First, a pipe-gate price is determined by averaging retrogressively from the distributor customers of the pipelines, using given estimates of transmission tariff demand charges and commodity surcharges. These latter tariffs are then adjusted so that they will reproduce the pipeline pipe-gate purchase price. Burner-tip prices are then propagated through the network to the markets, using surcharges derived from the model by Guldmann [5]. Finally, the surcharges are adjusted by the ratio of average observed prices on a State/market sector to the average State/sector price calculated above.

Setting rates by pipelines requires an estimate of the expected sales volume and the number of customers, in order to convert fixed charges to per-unit tariffs. Estimates are substantially based on census projections.

Market Clearing

Using the Gas Reserves Supply Table (GRST), production capability is determined from the parameters of the production profiles; reserves are drawn down by pipelines using committed supplies followed by the cheapest available gas. The resulting average price enters the market clearance calculations; the available supply is then delivered to markets.

As noted previously, base-year (1980) demand is given in Form FERC-50. For each subsequent year and for each market, there is a demand curve, which is based on current prices, previous year price and demand, plus other parameters.

Market clearance is, in principle, the solution of pairs of simultaneous equations. The simulated process is slightly more complicated in that each demand quantity at the wellhead results from accumulating demands from the markets backward through a pipeline system, accounting for distribution/transmission losses, transfers in and out of storage, and intersystem sales (those systems that are treated as take-or-pay) along the way. Prices start at the wellhead and are "marked up" as they move forward through the system to the burner-tip market.

In the event of a shortfall in supply, flows to all distributors in a pipeline system network are reduced by a common factor. Market curtailments are then represented by fulfilling market demands in priority order until supply is exhausted, by distributors with end-use customers.

After summer and winter market clearing, the market quantities and prices are combined to yield annual values in each pipeline system. The annual prices are used to update committed quantities in the base network. Demand function parameters are updated, and the annual process is then iterated, starting with aggregation of the committed quantities for pipeline system nodes, rate setting, and determination of available reserve supply blocks.

Structural attributes of the pipeline systems are fixed after base-year initialization. Customer relationships, storage capacities, and transmission or distribution loss factors are not altered. Moveover, in the base network, the "market shares" of take-or-pay gas furnished by all suppliers to a distributor are constant over time. Import supplies are also fixed throughout a simulation.

Storage occurs in the summer, with a total drawdown in the winter; the fraction of storage capacity employed each year is determined by half of the difference between winter and summer consumption in the previous year. Storage costs are calculated as a constant fraction (currently 0.25 percent) of the commodity cost of the stored gas. Although the model structure allows storage at all nonmarket nodes, storage is currently used only at pipeline nodes.

Each year, transmission and distribution tariffs, are increased by a fixed inflation factor, which is currently 2 percent.

A portion of natural gas consumption by utilities and industrial users is subject to alternate fuel capability. Switching is "automatically" triggered by prices equal to residual fuel oil prices multiplied by preset market-specific factors. For markets lacking alternate fuel capability, there are demand cutoffs determined by other (larger) market-specific multiples.

Natural Gas Demand Market

This section describes the determination of the demand for natural gas used in the Gas Analysis Modeling System (GAMS). In general, the set of demand models used to produce the 1982 Annual Energy Outlook (AEO) was used to produce the estimates of natural gas demand; however the additional regional detail required by Federal region (see Figure A5) for the demand quantities and switching levels, required additional adjustments. The 1982 AEO incorporated updates to the major assumptions concerning the world oil price, macroeconomic variables, and base period data in order to produce the natural gas demand forecast contained in this report. This section describes the updating procedure used, the changes in assumptions, and the methodology for reducing the complete set of energy demand functions into a simpler version of natural gas demands for use in GAMS. Unless otherwise noted, the remaining assumptions are based on those made in the 1982 AEO.

Residential, Commercial, Industrial and Electric Utility Fuel Demand

Residential, commercial, and industrial sector models are part of the Energy Information Administration's (EIA) Intermediate Future Forecasting System (IFFS). IFFS represents the U.S. energy supply, distribution, and consumption system by source of supply and sector of consumption. A base forecast of world energy prices, and a compatible macroeconomic projection of economic growth, drive four price-sensitive sectoral models of end-use energy consumption. Data-driven estimates of utility and refinery conversion capability and efficiency provide the derived demand for oil, coal, and natural gas by source. The model representation finds an equilibrium price for each fuel by balancing supply and demand in each year, to produce an energy balance. The implications of this result affect economic projections via levels of overall prices and terms of energy trade.

Household Model of Energy (HOME)

HOME simulates energy use in the residential sector of the economy annually through the year 1990. This is a comprehensive economic model that can be used to forecast demand for energy by fuel (electricity, oil, gas, other), by four end-use functions (space heating, water heating, air conditioning, and other), and for two types of housing (single-family units, and apartments and mobile homes. The residential simulation model is sensitive to the major demographic and economic determinants of residential energy use. HOME is the residential component of the IFFS (see above).

Econometric-Based Commercial End-Use Model

Provides forecasts of energy use for 1980 through 1990. This model of commercial energy use considers four end-uses (space heating, cooling, lighting, and other), four fuel types (gas, electricity, oil, and other, and six commercial subsectors (retail and wholesale, office activities, warehouse activities, institutions, hotels and motels, and miscellaneous commercial activities). Both economic factors and technological factors (equipment efficiency and thermal characteristics of buildings) are explicitly or implicitly represented in the model. The Econometric-Based Commerical Energy Use Model is the commercial component of the IFFS (see above).

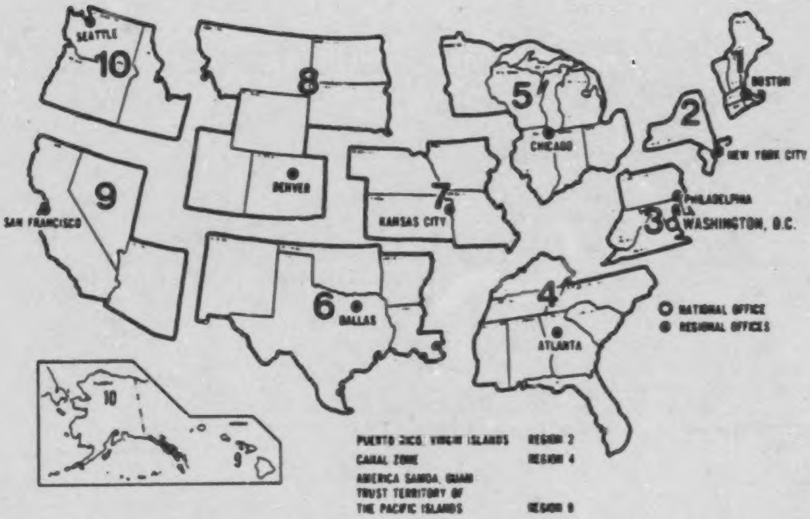
SEATTLE
10
8
5
1
BOSTON
2
NEW YORK CITY
CHICAGO
DENVER
9
SAN FRANCISCO
7
KANSAS CITY
PHILADELPHIA
3
WASHINGTON, D.C.
6
DALLAS
4
ATLANTA
NATIONAL OFFICE
REGIONAL OFFICES
10
9
PUERTO RICO, VIRGIN ISLANDS
REGION 2
CANAL ZONE
REGION 4
AMERICA SAMOA, GUAM
TRUST TERRITORY OF
THE PACIFIC ISLANDS
REGION 9

Figure A5. United States Map Showing Federal Regions

Purchased Heat and Power Systems

In the IFFS, industrial fuel consumption is divided into two major components: major and minor fuels. This distinction is based upon end uses/energy services which the fuels are consumed to produce and on the assumption of price sensitivity. Major fuels are consumed to fulfill boiler fuel, mechanical drive, process heat, and electrical services requirements, whereas minor fuels are consumed as raw materials or chemical feedstocks. In addition, major fuels are assumed to be own and cross price sensitive in some of their end-use applications, and minor fuels are assumed to be own price sensitive only. The natural gas demand component of the industrial sector is defined to exclude lease and plant fuel use. Both of these industrial end-uses are modeled in the purchased heat and power system (PURHAPS). PURHAPS forecasts use of energy purchased for heat and power by 17 manfacturing industries, and forecasts the State Energy Data System all-industry total. Forecasts of total energy use are made at the national level, based on econometric relations accounting for production levels, production growth, capital availability, etc., in data from 1958 through 1979. Designed to input annual regional economic forecasts and fuel prices from IFFS, and to output regional fuel use total to IFFS, through any final year chosen by IFFS. Supplemental equations forecast energy used as a raw material (notably chemical feedstocks, metallurgical coal and raw oil material), based on proxy price variables and national econometric relations, tied to variables such as pig iron production and petrochemical production, forecasted by special Data Resources Inc. (DRI) industry services. PURHAPS provides the industrial sector forecast to IFFS (see above).

Examination of the initial results of the industrial sector model showed the regional distribution of elasticities to be suspect because regions with low gas availability had higher elasticities than regions with higher availability. Therefore, the national elasticity was used in every region. Most industrial gas is consumed in Region 6. These figures dominate the national total.

In addition to the problem of regional distribution, the short-run industrial price elasticity of demand appeared to be small when compared to the residential and commercial sectors. Therefore, the literature showing the results of other industrial sectors models was examined. From this literature search, an alternative short-run elasticity more consistent with the values used in the residential and commercial sector was chosen. This short-run elasticity (-0.29) was used in place of the elasticity derived from the Oak Ridge Industrial Model (ORIM). The ORIM long-run elasticity was retained, and appropriate lag terms were derived.

Electric Utility Fuel Demand

Electric utility fuel demand is based upon the electric utility module of the IFFS. In IFFS, electricity is produced by fossil fuel, nuclear, and hydroelectric plants. A fourth category, labelled "other", includes geothermal power and electricity produced by burning wood and waste products and is contained in the hydroelectric totals. For the purposes of this report, the electric utilities sector consists of 7 separate fuel groups (coal, natural gas, distillate, low and high sulfur residual fuel oil, and hydro/other) plus imports of electricity. These inputs, after adjustments for generation and transmission losses, are used to meet total electricity demand by all end-use sectors.

Reduced Form Representation

IFFS produces estimates of energy demand for all purchased fuels. They include estimates for distillate fuel oil, residual fuel oil, natural gas, other petroleum products, and coal. Because this report emphasizes the demand for natural gas, much of the detail provided by these models was not needed. Therefore, a much simpler, reduced form version of the models was developed to represent the natural gas portion of demand. This reduced form version involves calculating a set of parameters, which characterize the demand curve for natural gas. The form of this relationship is:

$$\ln(Q'_{t,i}/Q^{\circ}_{t,i}) = B_i \ln(P'_{t,i}/P^{\circ}_{t,i}) + C_i \ln(Q'_{t-1,i}/Q^{\circ}_{t-1,i}) \qquad (1)$$

where Q° and P° represent the base quantities and prices, respectively, and Q' and P' represent the simulation (or values to be solved for) quantities and prices, respectively, for year t and sector i per region. Since this model is log-linear, B_i represents the short-term price elasticity of demand, and C_i represents a lag term that determines the long-run (B/1-C) price elasticity of demand.

The adjusted base quantities and prices were taken from the 1982 AEO. They represent the outputs of the models described above, and are adjusted for the changed assumptions previously discussed.

To obtain B and C, a series of Demand Analysis System (DAS) simulations over the 1980 to 1995 period was completed. In each simulation, the price path is perturbed by a constant percent; own elasticities are then computed between the base quantity price pair and the "perturbed case" pair. B_i is the own price elasticity of demand with respect to fuel price i, calculated for each year. Because the elasticities grow over time at a decreasing rate the 1995 elasticities are assumed to represent the long-term elasticity, and the expression $B_i/(1-C_i)$ is used to solve for C_i.

This methodology for determining the reduced form price and lag coefficients assumes that:

- the short-run elasticity is constant;
- the impact of a price increase in time period t is greatest in time period t and decreases thereafter; and
- all lagged effects of a price increase have occurred approximately after 15 years.

A system for automating these calculations has been implemented to allow recalibration and its reflection of different price or macro assumptions.

The short-term elasticities and lag values used in the model are summarized in Appendix B, Table B10.

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APPENDIX A

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Appendix B

INPUT DATA PARAMETERS AND ASSUMPTIONS

The basic underlying assumptions used in this report are the same as those used in the 1982 Annual Energy Outlook (1982 AEO) [1] except as noted in this appendix. Changes in assumptions can significantly alter the projections.

World Oil Prices

Trends in the oil market over the first few years of this decade have been dominated by two factors. One is the reduction in consumption, which has occurred in response to the sharp increase in the price of international crude oil since 1978. The second is the prolonged worldwide economic recession.

By the end of 1980, the world oil price was over $35 per barrel, up from $8 (1982 dollars) in 1973. The oil-importing countries have responded to this oil price increase with increases in general energy efficiency and substitution, where possible, of alternative fuels for oil. World energy markets in 1982 were characterized by a slack oil market and a decline in world oil prices. At year's end, world oil production capacity exceeded consumption by about 9 to 10 million barrels per day. Substantial liquidation of world oil inventories in 1982 helped to further soften world oil prices, which drifted downward from just over $34 per barrel in January to about $33 per barrel in December.

The world oil price, in real terms, is projected to fall through the mid 1980's before increasing in the latter half of the decade. Continued slow economic growth in the industrialized world and growing difficulties in international financial markets, particularly with respect to certain key oil-exporting countries, are expected to help keep oil markets soft over the next few years.

Three alternative oil price projections are used in this report and are shown in Table B1. The midprice projection, made by analyzing international oil supplies and demands, shows oil prices declining to a low of $25 a barrel in 1985 before increasing to $37 a barrel in 1990 (1982 dollars). The high and low price cases result from an assessment of higher and lower growth in demand and less and more optimistic supply assumptions.

Domestic oil prices peaked in 1981. This, together with the gathering recession in the United States, caused a rapid decline in the consumption of residual fuel oil and distillate fuel oil as industrial production declined and consumers reacted to prices. By the end of 1982, the prices of all petroleum products were well below the prices one year earlier.

Table B1. World Oil Price Projections
(1982 Dollars per Barrel)

Year	Low	Mid	High
1982	34	34	34
1983	28	30	32
1984	23	26	30
1985	21	25	34
1986	21	28	38
1987	22	32	41
1988	24	34	43
1989	26	36	45
1990	28	37	48

Source: 1982 Annual Energy Outlook

In this report, the price of home heating oil (No. 2 fuel oil) and the price of residual fuel oil (No. 6 fuel oil) are determined exogenously by using the margins determined in the 1982 AEO.

Macroeconomic Assumptions

The macroeconomic assumptions underlying the projections in this volume and those in the 1982 AEO also differ from those employed in previous years. In the past, a particular forecast obtained from a single forecaster (e.g., Data Resources, Inc. Chase Econometrics) was used. This year two different forecasts, one from Data Resources, Inc., and one from Dale Jorgenson Associates were employed to generate macroeconomic assumptions. These assumptions constitute input data for projections of energy markets and are not, in any sense, an independent EIA forecast of the economic future.

Table B2 presents assumed values of important economic variables underlying the forecast. Gross National Product--the total value of goods and services produced by the economy in a year--increases over the forecast period (1982-1990) at a rate of 3.2 percent a year, more rapidly during the initial years as the economy recovers. The overall rate of increase is somewhat below the rate of 3.5 percent that prevailed during the period between 1947 and 1980, but about the same as the overall rate of 3.2 percent that occurred during the 1970's. It is considerably above the rate of 1.8 percent observed between 1973 and 1982. The rate of growth assumed is in keeping with the recent trends in the economy.

Table B2. Assumed Values of Macroeconomic Input Variables

	Real GNP (Billions of 1982 Dollars)	Rate of Change	Disposable Income (Billions of 1982 Dollars)	Rate of Change	GNP Deflator (1972 = 100)	Rate of Change	Yield of Triple A Bonds
1980	3,054.4	-0.4	2,109.7	0.2	178.6	9.3	11.9
1981	3,113.8	1.9	2,161.5	2.5	195.5	9.4	14.2
1982	3,057.6	-1.8	2,185.1	1.1	207.2	6.0	13.8
1983	3,111.0	1.7	2,228.2	2.0	216.7	4.6	11.1
1984	3,253.4	4.6	2,332.9	4.7	227.8	5.1	10.4
1985	3,394.4	4.3	2,420.5	3.8	240.3	5.5	10.3
1986	3,505.5	3.3	2,495.3	3.1	254.4	5.9	10.4
1987	3,614.3	3.1	2,551.5	2.3	271.1	6.6	10.4
1988	3,705.7	2.5	2,592.7	1.6	290.5	7.1	10.4
1989	3,804.5	2.7	2,653.1	2.3	310.7	7.0	10.1
1990	3,920.4	3.0	2,719.2	2.5	331.7	6.8	9.8

The energy and economic values used in this report are expressed in constant 1982 dollars. In other words, the projected value of energy services in some future year is expressed in terms of the number of 1982 dollars required to purchase the services. The index used to convert current prices to constant dollar prices is the "implicit price deflator" for GNP--the ratio of GNP in current dollars to GNP in constant dollars.

The GNP deflator is only one of a number of measures of inflation; others include the Producer Price Index and the Consumer Price Index. The GNP deflator is employed here because of its broad base and the ubiquity of energy use in the economy. Over the 1980 to 1990 period, the GNP deflator is assumed to increase relatively smoothly at a rate of 5.6 percent. This rate is somewhat below the rate of 7.8 percent experienced since 1973 and reflects recent decreases in inflation.

Disposable income and interest rates are other variables that play important roles in determining energy demands in different sectors of the economy. The level of disposable income is an important determinant of personal energy use.

Incremental Pricing

Title II of the Natural Gas Policy Act of 1978 (NGPA), Incremental Pricing, contains provisions for allocating a portion of the costs of certain high-priced natural gas directly to industrial users who buy gas in the interstate market. These costs, accumulated in a special set of accounts kept by the pipeline company, are passed on to "nonexempt" industrial users in the form of a surcharge, but only up to a ceiling level, the price of alternative fuel. Effective January 1, 1980, most large industrial boiler fuel facilities (i.e., those using 300 Mcf of gas or more per day in 1977) in the interstate market became nonexempt.

Federal Energy Regulatory Commission (FERC) orders prescribe the method by which Title II, Phase I, is implemented. FERC Orders 50 (Docket No. RM 79-21, September 29, 1979), 167 (Docket No. 81-27, July 24, 1981), and 181 (Docket No. 81-28, October 6, 1981) stipulate that the alternative fuel price ceilings will be based upon high-sulfur No. 6 residual fuel oil. Sales volumes and prices are from the Energy Information Administration (EIA) on Form EIA-194, "Monthly Alternative Fuel/Incremental Price Monitoring Report." The latest 3 months' submissions of these data are used to calculate alternative fuel price ceilings, which are published in the Federal Register on or about the 20th of each month.

Title II, Phase II, which would have broadened the scope and impact of the incremental pricing provisions, was vetoed by the United States Senate. The constitutionality of veto by only one House of Congress is now under judicial review.

In theory, the effect(s) of incremental pricing would appear to be relevant to the analysis of NGPA alternatives. In practice, it is not, for the following reasons:

- Phase II has not been implemented.
- Most State public utility commissions have tied State price ceilings to the ceilings published by EIA. Because of the relatively small amounts of gas sold to nonexempt users, the beneficial effect of incremental pricing on exempt users (including residential customers) has been very small.

- Industrial gas prices are already near or above the alternative fuel price ceiling in many areas.

For purposes of this analysis, for the scenarios in which Title II of the NGPA continues in force, incremental pricing was modeled as currently implemented and was assumed not to change the overall results.

Lower-48 Reserves, Production and Prices

Reserves and Production

Analysis of the supply outlook through 1990 requires detailed data on prices, reserves, and production for each NGPA Section and for each pipeline system. These data are not available from a single source; consequently several data sources were used either directly or to allocate the information to the level of detail required.

Reserves, production and price data were developed for 17 domestic pipeline systems (Appendix A, Table A1). Reserves and production data were obtained from two sources, Forms FERC-15 and EIA-23.

The FERC-15 data [2] include reserves and production information reported by interstate pipeline companies for different geographic areas. Data from this form (published in Table 26 of Reference 2) were used as the control total for the interstate pipeline companies listed in Table A1.[1]

The Form EIA-23 survey [3], a sample of oil and gas operators stratified by size, contains data on total reserves and production for each state. To obtain estimates of intrastate data by state, the FERC-15 data were aggregated for the interstate pipelines by state and then subtracted from EIA-23 estimates of 1980 total reserves and production of dry gas (published in the Table 12 of Reference 3). The FERC-15 and EIA-23 data are not strictly comparable, because the two forms request information under slightly different definitions and because the FERC-15 data exclude lease and plant fuel use. The EIA-23 data were reduced by 7.5 percent to exclude this gas.

To allocate reserves and production by NGPA Section, two additional data systems were used. The Purchase Gas Adjustment data provide projected wellhead purchase volumes by NGPA Section for 20 interstate pipeline companies. These were used to allocate reserves and production for those 20 companies, using the ratio of purchases by Section to total purchases. The remaining interstate companies and intrastate area reserves were apportioned in a similar manner, using the FERC-121 and FERC-123 data system [4], which includes data on production by region, company, interstate or intrastate market, and NGPA Section and Subsection.

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[1] This included all but three of the companies listed in Table 26 of Reference 43. Data from other sources indicated that Kentucky West Virginia Gas Company, Louisiana Nevada Transit Company, and Mid Louisiana Gas Company were principally involved in intrastate markets, and therefore these were not included.

The following obvious anomalies in the data were adjusted on the basis of information from other sources and judgmental estimates:

- Sea Robin Pipeline Company's reserves from the FERC Form 15 were split equally between United Gas Pipeline Company and Southern Natural Gas Company. In 1980 Sea Robin sold gas only to these two companies on an approximately equal basis [2]. This was assumed to be NGPA Section 104 gas.
- Because of the large reserves supporting Section 107 gas, a minimum reserves-to-production ratio of 10 was assigned if the calculated number was less than 10. In those cases, the reserves for the Section 107 gas were adjusted upward, and those for the other NGPA Sections were adjusted downward proportionately.
- The EIA-23 survey is a sample survey and consequently is subject to both estimation and sampling errors. In some cases, differencing between the EIA-23 data and FERC-15 data produced negative or very small values for intrastate reserves. For Texas, Louisiana, and Oklahoma, reserve estimates published in the Part I study were assigned (See Reference 4, page 40). Kansas and New Mexico were assigned reserve levels from the column entitled Form EIA-23 Intrastate and "Other" Commitments. Other data from Form EIA-23 illustrate the range of uncertainty associated with these reserve data, as shown in Table B3.
- For production estimates, differencing often gave low values for intrastate production. The Part I estimates of production were assigned for Louisiana, Texas and Oklahoma (see Table B4).

Table B3. Intrastate Reserve Commitments
(Trillion Cubic Feet)

State	Calculated	Assigned	Form EIA-23 Intrastate and "Other" Commitments 1980[b]	Form EIA-23 Uncommitted or Unknown 1980[b]	Form EIA-23 Sampling Errors 1981[c]
Kansas[a]	0.3	1.2	1.1	1.0	0.8
Louisiana ...	7.3	8.1	6.1	6.6	0.3
New Mexico ..	-2.5	1.0	1.1	0.2	1.1
Oklahoma	3.1	3.8	3.2	3.5	0.6
Texas	25.4	27.9	18.0	11.2	0.7

[a] Interstate reserves for Kansas were adjusted downward by 1.2 Tcf; this is the calculated difference after that adjustment.

[b] Data adjusted to "dry" net of lease and plant fuel, using the ratio of reserves, wet to dry from Reference 3, Tables 9 and 12, and a 7.5 percent reduction for lease and plant fuel.

[c] Error is for "wet, after lease separation."

Source: References 2, 3, and 5.

Table B4. Intrastate Production
(Trillion Cubic Feet per Year)

State	Calculated	Assigned
Louisiana	0.9	1.1
New Mexico	([a])	0.1
Oklahoma	0.5	0.6
Texas	2.9	3.3

[a]Less than 0.05.
Source: References 2 and 3.

Prices

Wellhead prices for gas produced in 1980 were obtained from the Form EIA-758 ("Natural Gas Producer/Pipeline Contract Report") and Purchase Gas Adjustment data (PGA) [6]. The PGA data provided the prices for 1981 through 1983 for the 20 interstate pipelines for which they were available.

Data from Natural Gas Pipeline/Producer Contracts: A Preliminary Analysis and the Form EIA-758 were used to provide the distribution of contract escalation clauses for existing contracts or contracts in effect prior to 1981. For new contracts, the NGPA ceiling price was assigned until decontrol; after decontrol, the price for "other deregulation clauses" was assigned.

For those cases in which the gas is scheduled for decontrol and the contract specifies a deregulation provision, the contract was considered to have the highest-allowed regulated rate until the decontrol date. Similarly, contracts with deregulation clauses for gas not scheduled to be decontrolled were considered to be highest-allowed regulated rate contracts.

All prices are factored upward by a minimum of 10 percent to allow for severance taxes and gathering charges. For each solution year in GAMS, adjustments are made to the price of gas to reflect an estimate of contract price escalator clauses. The prices implied by the contract provisions are entered in the Gas Reserves Supply Table for each solution year. Table B5 provides the prices assigned to each escalator clause by alternative scenarios.

Lower-48 Supply Projections

Conventional Gas

The projected supplies of conventional natural gas from the onshore areas of the Lower-48 States are provided by the Production of Onshore Lower-48 Oil and Gas Model (PROLOG). The PROLOG methodology and data are described in the EIA publication "Production of Onshore Lower-48 Oil and Gas Model: Methodology and Data Description"

Table B5. Price Assumptions by Policy Cases

Category	Price by Policy Case		
	Reference Case and Phased Decontrol	Continued Controls	Administration Proposal
Deregulation Clause, Oil Parity with No Market-Out	110 percent of the price of distillate fuel oil.	110 percent of the price of distillate fuel oil only for Section 107 gas deregulated prior to January 1, 1983. For Section 107 gas classified after December 31, 1982, the price allowed is limited to 70 percent of the refiner's acquisition cost of crude oil.	
Deregulation Clause, Most-Favored-Nation Clause with No Market-Out	Last year's highest average price.	Last year's highest average price for Section 107 gas deregulated prior to January 1, 1983. For Section 107 gas classified after December 31, 1982, price is lower of last year's highest average price or 70 percent of the refiner's acquisition cost of crude oil.	Section 107 deep gas (currently deregulated) is capped at the higher of the gas cap price or price in effect at time of enactment. Tight sands gas is capped at the maximum allowable price on the date of enactment. Price regulations are removed from any new contracts signed after enactment or renegotiated contracts. On January 1, 1985, for any contract that has not been renegotiated, either party may exercise a "market-out" or abrogate the contract.
All Other Deregulation Clauses	Decontrol price for new contracts.	Decontrol price for new contracts for Section 107 gas deregulated prior to January 1, 1983. For Section 107 gas classified after December 31, 1982, price is lower of decontrol price for new gas or 70 percent of the refiner's acquisition cost of crude oil.	It is assumed that all contracts in existence prior to enactment are renegotiated in 1985 and are given the decontrol price for new contracts. Any new contract receives the decontrol price.
Highest Allowed Regulated Rate	NGPA ceiling price.	NGPA ceiling price.	Ceiling price is the lower of the NGPA ceiling or "average" new decontrol price (gas cap) until deregulation on January 1, 1986. However, all contracts in existence prior to enactment are considered renegotiated in 1985 and are assigned decontrol price for new contracts.
Definite Only	Price for that category tabulated from Form EIA-758. Price is assumed to hold constant in real terms.	Price for that category tabulated from Form EIA-758. Price is assumed to hold constant in real terms.	Price for that category tabulated from Form EIA-758. Price is assumed to hold constant in real terms through 1984. In 1985 all contracts are decontrolled and assigend decontrol price for a new contracts.

[7]. Changes in the methodology as established in this report are described in an internal memorandum within the Natural Gas Division of EIA [8].

A number of features of the model require user-specified parameter values, including discount rates, costs, finding rates, and productivity, as described below. The discount rates used in the discounted cash flow (DCF) calculations are generally 10 percent for developmental drilling projects and 12 percent for exploratory drilling projects. During the years 1982 and 1983 the discount rates are 15 and 18 percent for developmental and exploratory drilling projects, respectively. The higher rates reflect the influence of greater uncertainty in those years surrounding the world oil price and the regulatory environment in the natural gas market. The expected prices used in the DCF calculations are based on expected constant prices. Revenue values in the DCF computation include revenues from coproducts.

Other user options are related to the costs of exploration and development. All growth rates refer to real changes in costs. Drilling costs grow at 3 percent per year. Since marginal lease acquisition costs are close to zero, lease acquisition costs are set at zero. Geological and geophysical costs, estimated from data in the Annual Survey of Oil and Gas [9], grow at 5 percent per year. Lease equipment costs and operating costs also estimated from this data are constant in real terms.

The high and low supply cases are based on changes to base case costs and productivity. The high supply specification assumes no long-term growth in real drilling costs; a 10 percent reduction in initial year drilling costs; and finding rates 10 percent higher than in the base case. The low supply scenario assumes a long-term growth of 6 percent annually in drilling costs; an additional 10 percent increase in initial year drilling costs; and finding rates 10 percent lower than in the base case.

Unconventional Gas

The unconventional gas recovery (UGR) projections are based heavily on the 1980 study conducted by the National Petroleum Council (NPC) [10]. Unconventional gas generally refers to gas resources characterized by geologic environment: tight formation gas reservoirs (often referred to as "tight sands"), Devonian shale, coal seams, and geopressurized brine. Gas from coal seams and geopressurized brine is not included in the supply forecasts, due to the relatively low projected overall contribution to natural gas supply in the time frame of the report. In addition, the high degree of uncertainty surrounding these resources as potential sources of supply in this decade further reduces the expected activity levels.

Natural gas from tight sands reservoirs and Devonian shale is included in the present analysis as unconventional gas supply. The projected reserve additions are shown in Table B6. The first three columns in Table B6 list figures adapted from the 1980 NPC report on unconventional gas sources; the fourth column lists the reference forecast for GAMS. The fifth column presents the reference prices associated with the volumes of reserve additions. The NPC study is quite optimistic concerning tight sands reservoirs, and some doubt has been expressed as to whether the indicated production levels are achievable. Critics have charged that the projected tight sands figures are too high. For example, NPC estimated that 365 Tcf of gas could be recovered from tight gas reservoirs in the Lower-48 States, given current technology and a wellhead price of $5.85 per MMBtu (in 1982 dollars). Such an estimate seems quite high, considering that this figure almost matches the estimate of 390.2 Tcf released by the U.S. Geological Survey in 1981 for total recoverable conventional gas resources

Table B6. Projected Reserve Additions for Unconventional Gas (Trillion Cubic Feet)

	NPC Estimate				
Year	Devonian	Tight Sands	Total	GAMS Reference Forecast	Reference Price (1982 Dollars Per MMBtu)
1981 ...	0.42	1.52	1.94	0.29	4.81
1982 ...	0.60	2.60	3.20	0.54	5.22
1983 ...	0.77	3.73	4.50	0.85	5.64
1984 ...	0.92	4.87	5.79	1.20	6.08
1985 ...	1.00	6.04	7.05	1.60	6.56
1986 ...	1.16	7.78	8.94	2.20	6.98
1987 ...	1.31	9.60	0.91	2.90	7.43
1988 ...	1.47	11.49	12.96	3.69	7.95
1989 ...	1.47	13.44	14.90	4.56	8.50
1990 ...	1.47	15.40	16.86	5.52	9.09
Total ..	10.57	76.48	87.04	23.35	

Source: NPC Estimate [10].

in the Lower-48 States [11]. In fact, the NPC report conceded that a number of factors would influence the rate of recovery from unconventional sources. The GAMS reference volumes of Table B6 presents the modified set of projection values used as the starting point used in this analysis. The adjustments were made on the basis of the following considerations:

- The drilling levels implicit in the NPC estimates of reserve additions were determined exogenously, based on fixed levels of resources such as drilling rigs.
- The resource base was estimated by the NPC using a simple extrapolation technique. In light of the simple methodological approach and the extreme nature of the result, the tight sands resource base is considered highly speculative.
- The technology for producing from tight sands and Devonian shale, while commercially feasible for certain projects to date, is still being refined. The NPC assumed that the production methods would be economically viable in all areas of the country.
- The lack of supporting infrastructure, especially pipeline facilities, in new gas-producing areas may discourage exploration and development.
- In some cases, gas from tight sands formations is included with conventional gas in calculating the finding rate. Currently economic and producing reserves include tight gas formations which affect the finding rate for gas drilling.

In the GAMS model implementation, the actual volume of UGR reserve additions varies in response to the price. The reference figures in Table B6 constitute the starting point for the URG projections. Deviations from the reference prices result in changes in the level of reserve additions based on an assumed elasticity of 0.5. This adjustment process was incorporated into the model to limit the development of UGR to more realistic levels.

Outer Continental Shelf

The Outer Continental Shelf (OCS) Model forecasts require a number of user-specified parameters. The discount rate is 9 percent in all present-value computations.

The OCS projections for the Gulf of Mexico from the model appear in Tables B7 and B8. Forecasts for the Atlantic and Pacific areas are not shown, as these areas do not exhibit significant natural gas reserve additions during this decade in the model. The pattern of the gas reserve additions from the model is rather troublesome. The values for the first two years are roughly double the historical levels, and the figures fall rapidly in the following years. Reserve additions fall below 1 Tcf by 1990. However, the cumulative reserve additions over the time horizon seem reasonable. In this situation it was decided to smooth the forecasts using an ordinary least squares regression technique. The results of the regression procedure are shown in the second column of Table B7.

The high and low geology cases used the coefficient of variation for gas resources in the OCS model run. The coefficient of variation is measured by the ratio of the standard deviation to the expected resource level. The value was 0.1874. The high supply forecasts equalled the base values times 1.1874 and low the base values times (1.0-0.1874). The three sets of supply forecasts are shown in Table B8.

Alaska

Alaska as a source of natural gas is omitted, but not ignored. The expected start date for flow of gas from Prudhoe Bay has steadily receded. The earliest official date is late 1989. Given the high degree of uncertainty surrounding several key issues, most notably the financing of the pipeline, Alaska is not included in the group of domestic (Lower-48) supply sources in this analysis.

Gas Imports

Natural gas imports in the model are included in the "supplemental" sources of gas supplies available to interstate and intrastate pipelines, which beyond a fixed level of purchases, are used as deemed necessary by these pipelines to meet market demands. Canadian imports were generally allocated among the pipeline systems developed for the model on the basis of historical dependency. The authorized level of imports was reduced, however, to reflect market conditions that have forced a number of the pipeline importers to reduce import volumes below authorized levels. Current estimates place Canadian imports at approximately 50 percent of authorized levels. Recognizing that the Northeast is likely to become more dependent on Canadian imports, additional volumes were allocated to this region. The basis of this allocation is the authorization by the Economic Regulatory Administration (ERA) to allow Boundary Gas to import 185,000 Mcf of Canadian gas per day (approximately 67.5 Bcf per year). Boundary Gas consists of 13 natural gas distribution companies and one pipeline company, marketing natural gas in New York, in New England, and to a lesser degree in New Jersey and Pennsylvania. Deliveries under this authorization are assumed to commence January 1, 1984. No attempt was made to include additional imports from Canada to Transcontinental Gas Pipeline Company and Tennessee Gas Pipeline Company that have recently been authorized by ERA.

Table B7. Gas Reserve Additions for the Gulf of Mexico: Projected and Fitted Reserve Additions, 1986-2000 (Tcf)

Year	OCSM Projected Reserve Additions	Fitted Reserve Additions
1986	6.71	2.31
1987	4.47	2.23
1988	1.95	1.97
1989	1.40	1.84
1990	0.58	1.70
1991	0.37	1.57
1992	0.15	1.44
1993	0.10	1.31
1994	0.10	1.18
1995	0.12	0.97
1996	0.03	0.92
1997	0.17	0.78
1998	0.21	0.65
1999	0.02	0.52
2000	0.08	0.39

Table B8. Gas Reserve Additions for the Gulf of Mexico: Low, Base and High Geology Scenarios, 1981-2000 (Tcf)

Year	Low	Base	High
1981	2.97	3.66	4.34
1982	1.74	2.14	2.54
1983	2.69	3.31	3.93
1984	1.53	1.88	2.23
1985	2.56	3.15	3.74
1986	1.87	2.31	2.74
1987	1.81	2.23	2.64
1988	1.60	1.97	2.34
1989	1.49	1.84	2.18
1990	1.38	1.70	2.02
1991	1.28	1.57	1.87
1992	1.17	1.44	1.71
1993	1.06	1.31	1.56
1994	0.96	1.18	1.40
1995	0.79	0.97	1.16
1996	0.74	0.92	1.09
1997	0.64	0.78	0.93
1998	0.53	0.65	0.77
1999	0.42	0.52	0.62
2000	0.32	0.39	0.46

Further, the assumption was made that imports from Canada would generally prevail at current import levels, and that in those instances where import licenses are due to expire prior to the end of the forecast period of the study, the importers would be able to renew contracts and receive necessary regulatory approval to maintain their import levels for the duration of the forecast period. With regard to Mexican imports, the total volumes imported are relatively small compared to Canadian imports. For purposes of this study, the volumes were allocated among the various pipelines importing the gas, on the basis of currently authorized volumes. It was assumed that these volumes would continue for the duration of the forecast period of the study. No attempt was made to include the prospect that additional imports might be obtained from Mexico.

For LNG imports, which currently are limited to the New England area, it was assumed that imports by Columbia Gas Transmission Corp. and Southern Natural Gas Company, which have been suspended since 1980, would resume at authorized levels in 1985. In the case of Trunkline LNG company, it was assumed that deliveries for this project would commence in 1984.

In terms of prices for imports, it was generally assumed for this study that gas imports would be priced on the basis of prevailing world crude oil prices. This is the basic pricing strategy applied by Canada, Mexico, and Algeria. In the case of Canada, the export price is $4.94 per MMBtu, effective July 1, 1981 but was reduced to $4.40 per MMBtu in recognition of the drop in world oil prices. In the case of Mexican gas imports, the price remains at $4.94 per MMBtu, and is subject to adjustment proportional to the average price of five crude oils traded on the world market.

In the case of LNG imports, the same basic pricing strategy of equivalency to world oil prices was applied, adjusted slightly upward to reflect the higher costs associated with LNG terminals.

Transmission and Distribution

The bidding behavior of a pipeline system is highly dependent on its expectations of demand. It is assumed that after satisfying take-or-pay requirements, pipeline systems will purchase gas at the minimum possible cost each year, and that once gas has been committed to a pipeline system, it will remain in that system. Sales between pipeline systems, both interstate and intrastate, are assumed to remain in fixed proportion to sales value through the forecast horizon. Gas distributors are assumed to have no decision flexibility on gas purchase prices, and to allocate prices to end-users on the basis of a set formula.

Historically, pipelines have had problems obtaining enough gas to satisfy their customers. This situation has resulted in additional spot market purchases and curtailments. Through 1990, additional gas is assumed to be available for each pipeline system at 130 percent of the price of No. 2 fuel oil. This supply can be interpreted in several ways: it could be a short-term purchase of domestic or import gas at a high price; it could be synthetic natural gas; or, alternatively, it could be recorded as unavailable, i.e., as curtailments or markets lost involuntarily to alternate fuels.

Demand

The base consumption flows for 1980 is defined by Form FERC-50 data. End-use consumption is calibrated to the Form EIA-176 survey [12]. In both the industrial and electric utility sectors, some end-users have boiler capacity that can burn either residual fuel oil or natural gas. These users are assumed to switch fuels when the economics of operating the boiler makes the other fuel more cost-effective. In addition to switching fuels in dual-fired boilers, the electric utility industry can reverse the utilization of non-dual-fired oil and natural gas boilers to further shift consumption from natural gas to residual fuel oil. For industrial use and electric utilities, consumption by dual-fired boilers is assumed to vary from region to region, as shown in Table B9.

Finally, natural gas consumption, particularly in the residential market, is highly dependent on weather conditions. In this analysis, no adjustment was made for climatic variations. The weather conditions used throughout are implicitly those experienced in 1980. As a result, a much colder winter in 1984, for example, could result in higher consumption volumes for the New England area than projected in this report.

Table B9. Estimated Electric Utility and Industrial Gas Consumption in Dual-Fired Boilers in Different Regions of the United States

Region	Gas Consumed in Dual-Fired Boilers (Percent of Total Gas Consumption)
Federal Region	Electric Utilities
1	100
2	100
3	100
4	93
5	81
6	26
7	82
8	53
9	98
10	0
Census Region	Industrial
Northeast	16
North Central	16
South Atlantic	18
South Central	15
West	11

Sector Demand Curves

The residential, commercial, and industrial models discussed in Appendix A were used to project natural gas demand by region, annually between 1980 and 1990. This demand forecast is used to generate the base quantity and price values (Q^* and P^*) shown in equation (1) in Appendix A. The Short-term elasticity and lagged response in equation (1) in Appendix A are identified in Table B10. The results of the analysis are summarized in Table B11 for the Nation. These data are used to calculate rates of changes in reference prices and quantities. These rates are applied to 1981 actuals taken from the Natural Gas Annual. The resulting values are input to GAMS and used as reference prices and quantities in the demand calculations. As previously noted, the actual projections are made on a regional basis.

Table B10. Parameter Estimates for the Reduced-Form Natural Gas Demand Model

Sector	Short-Term Elasticity (B)	Lag-Term (C)
Residential	-0.14	0.68
Commercial	-0.23	0.45
Industrial		
Non-boiler	-0.26	0.77
Boiler	-0.26	0.79
Raw Materials ..	0.0	0.0

Source: Oak Ridge Residential, Commercial, and Industrial Energy Models

Table B11. 1982 AEO Price and Quantity Data Used to Generate Reference Prices and Quantities (Quadrillion Btu; Real 1982 Dollars per Million Btu)

	Residential		Commercial		Industrial	
Year	Quantity	Price	Quantity	Price	Quantity	Price
1981	4.65	4.82	2.58	4.46	7.31	3.63
1982	4.79	4.96	2.68	4.64	5.99	3.72
1983	4.71	5.16	2.72	4.85	5.82	3.86
1984	4.65	5.71	2.73	5.40	5.76	4.27
1985	4.59	6.65	2.72	6.42	5.21	5.62
1986	4.52	7.43	2.69	7.24	5.11	6.45
1987	4.46	8.01	2.64	7.85	5.19	7.00
1988	4.41	8.28	2.59	8.14	5.48	7.13
1989	4.38	8.35	2.54	8.27	5.70	7.17
1990	4.35	8.53	2.50	8.48	6.00	7.23

Note: Industrial includes all industrial uses of natural gas (boiler fuel, process heat, and raw materials, including refinery fuel consumption) except for lease and plant fuel.

Sensitivity Cases

Two sensitivity cases were developed to examine some of the underlying uncertainty in the demand forecast surrounding the 1982 AEO base case demand projections. These were high and low demand cases. They assume a natural gas price identical to that used in the base case but vary other assumptions to determine a possible range for the demand forecast. They were designed to capture a reasonable range of uncertainty. The results of this sensitivity analysis are presented in Table B12, in which the levels of natural gas demand for each sector and case are presented for 1985 and 1990.

Table B12. Low and High Demand Data Used to Generate Reference Quantities for the Demand Sensitivity Cases
(Quadrillion Btu)

		Case		
Sector	Year	Low Demand	Base	High Demand
Residential ...	1982	4.7	4.7	4.7
	1985	4.4	4.6	4.8
	1990	3.9	4.4	4.9
Commercial	1982	2.7	2.7	2.7
	1985	2.6	2.7	2.8
	1990	2.2	2.5	2.8
Industrial	1982	6.0	6.0	6.0
	1985	5.0	5.2	5.4
	1990	5.3	6.0	6.7
Total	1982	13.4	13.4	13.4
	1985	11.9	12.5	13.1
	1990	11.4	12.9	14.4

In the residential and commercial sectors, it was assumed that demand could be 10 percent higher or lower than the base quantity by 1990. Between 1983 and 1990, this percentage was linearly interpolated from 0 in 1982. The 10 percent figure is based on judgment.

In the industrial sector, it was assumed that demand could be 10 percent higher or lower over the entire 1983 to 1990 time period. The assumption differs from that made in the residential and commercial sectors because of the possibility of "latent" demand in the industrial sector. This is the demand that would be met if supply became available and, while considered unlikely, is nevertheless a possibility.

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Appendix C

COMPARISON WITH HISTORICAL DATA AND OTHER PROJECTIONS

This appendix documents differences in published historical and forecasted values for some major natural gas information contained in this report. The series addressed are similar to the principal series published annually in the Natural Gas Annual.

Table C1 compares output from the Gas Analysis Modeling System (GAMS) with historical values from the Natural Gas Monthly (NGM) and the Natural Gas Annual (NGA) based on the Form EIA-176, as well as information from the Form FERC-50. GAMS uses Form FERC-50, "Alternate Fuel Demand Due to Natural Gas Deficiencies," for representing distribution and consumption behavior.[1] This is primarily because the Form FERC-50 collects monthly data from which important statistics on seasonal characteristics of the natural gas market can be calculated and also because it contains detailed information on the transactions prior to final sales to end-use markets. However, since the Form EIA-176 data series is considered to be more comprehensive and reliable, an attempt is made to control aggregate 1980 GAMS results to this series. The 1981 data are used to determine whether the direction of change from 1980 to 1981 data is replicated by GAMS. Another purpose is to compare the numerical difference between the GAMS representation of what occurred in natural gas markets in 1981 and the Form EIA-176 representation. Differences are not surprising. Although Form EIA-176 is a reliable guide as to what happened, it is not an exact representation of the totality of transactions that occurred in natural gas markets in any one year.

Tables C2 and C3 compares 1985 and 1990 GAMS projections with those of other studies. The reports which are included in this comparison are:

1. American Gas Association, Policy Evaluation and Analysis Group, The Winter 1983 A.G.A. - TERA Base Case, Arlington, Virginia, February 8, 1983.

2. U.S. Department of Energy, Office of Policy Planning and Analysis, A Study of Alternatives to the Natural Gas Policy Act of 1978, Washington, D.C., November 1981.

3. Energy Information Administration, U.S. Department of Energy, Analysis of Economic Effects of Accelerated Decontrol of Natural Gas Prices, Washington, D.C., August 1981).

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[1] Unlike Form EIA-176, Form EIA-50 does not collect data on the volumes consumed directly by producers, e.g., pipeline fuel, refineries, and petrochemical feedstocks.

4. Energy Information Administration, U.S. Department of Energy, Annual Report to Congress, Volume 3, Energy Projections, Washington, D.C. February 1982.

5. Energy Information Administration, U.S. Department of Energy, 1982 Annual Energy Outlook, DOE/EIA-0384(82) Washington, D.C., May 1983.

These tables provide a convenient means for an analyst to perceive the variability in forecasts from several other studies. The numbers in the tables vary because of differences in forecasting techniques, definitions, and in the currency and completeness of the historical record of events in the natural gas markets accessed in developing the projections. Readers who wish to pursue these differences further may do this by examining the documentation associated with the cited reports.

Table C1. Aggregate Statistics and Forecasts[a]
(Quadrillion Btu; 1982 Dollars per Million Btu)

Parameter	Source	1980	1981	1982
Marketed Production[b]	NGM	20.5	20.3	18.5
	GAMS	20.6	20.6	19.0
Average Wellhead Price	NGM	1.80	2.04	2.35
	GAMS	1.80	2.05	2.25
Imports	NGM	1.01	0.93	1.0
	GAMS	1.01	0.92	0.90
Total Delivered to Consumers				
Quantity	NGM	18.56	18.20	16.77
	FERC-50	17.95	17.59	--
	GAMS	18.56	18.50	16.98
Average Price	NGA	3.30	3.63	--
	GAMS	3.36	3.77	3.99
Residential Consumption				
Quantity	NGM	4.87	4.66	4.82
	FERC-50	4.93	4.72	--
	GAMS	4.86	4.68	4.84
Average Price	NGA	4.16	4.43	--
	GAMS	4.22	4.78	4.97
Commercial Consumption[c]				
Quantity	NGM	2.66	2.57	2.66
	FERC-50	2.78	2.65	--
	GAMS	2.66	2.59	2.70
Average Price	NGA	3.85	4.14	--
	GAMS	3.89	4.45	4.68
Industrial Consumption				
Quantity	NGM	7.29	7.27	6.01
	FERC-50	6.76	6.54	--
	GAMS	7.27	7.38	6.06
Average Price	NGM	2.92	3.26	--
	GAMS	2.94	3.32	3.42

Table Cl. Continued

Parameter	Source	1980	1981	1982
Electric Utility Consumption				
Quantity	NGM	3.75	3.71	3.29
	FERC-50	3.47	3.69	--
	GAMS	3.78	3.86	3.38
Average Price	NGA	2.57	3.00	--
	GAMS	2.66	2.96	3.05

[a] Excludes Alaska.

[b] Marketed production, net of Alaska, was converted to MMBtu from Mcf using 1.027 MMBtu per Mcf.

[c] Commercial equals Commercial plus Other Consumption.
Note: NGA represents values from Energy Information Administration, Natural Gas Annual FERC-50 indicates a value obtained from Federal Energy Regulatory Commission (FERC) Form-50. NGM indicates 1982 values were obtained from the Energy Information Administration, Natural Gas Monthly. In order to correct 1982 quantities for Alaskan and Hawaiian gas, the proportion of Alaskan and Hawaiian gas to total gas in 1981 was subtracted from 1982 reported quantities.

Note: The conversion factors which are used in this section are:

1. For converting cubic feet (cf) of natural gas into British thermal units (Btu) (Source: Monthly Energy Review, March, 1983.)

    a) 1979 - 1021 Btu per cf.
    b) 1980 - 1026 Btu per cf.
    c) 1981 - 1027 Btu per cf.
    d) 1982 - 1027 Btu per cf.

2. For converting nominal dollars into constant dollars the GNP deflator is used:

    a) 1979 - 163.42
    b) 1980 - 178.64
    c) 1981 - 195.51
    d) 1982 - 207.23

Table C2. Comparison of Various Forecasts for the Natural Gas Market in 1985
(Quantities in Quadrillion Btu; Prices in 1982 Dollars Per Million Btu)

Category	EIA-GAMS[a]	AGA-TERA[b]	Alternative Report[c]	Economic Effects Report[d]	EIA Annual Report[e]	EIA Annual Outlook[f]
Supply						
Domestic Production	18.42	18.37	17.7	16.95	18.5	15.2
Average Wellhead Price	$3.19	$3.84	$5.03	$6.22	$4.18	$3.60
Imports and Supplemental Supply	1.28	1.4	2.0	1.74	0.82	1.2
Total	19.71	19.77	19.7	18.69	19.32	16.4
Consumption						
Residential/Commercial	7.51	8.34	7.9	7.45	7.5	7.3
	$6.04	$5.93	$7.45	$7.01	$6.16	$6.56
Industrial	6.17	7.74	6.5	8.48	9.4	5.2
	$4.59	$5.45	$6.33	$6.41	$5.34	$5.57
Electric Utilities	3.16	2.82	2.9	2.25	2.36	1.7
	$4.10	$5.41	--	$6.64	$5.60	$5.54
Other Uses	2.9	0.87	2.4	0.5	0.4	2.2
Total	19.71	19.77	19.7	18.69	19.66	16.4

[a] Difference between total supply and total consumption includes lease and plant fuel use and transportation and distribution losses. These volumes are not modeled explicitly and so not provided.

[b] Other uses in this report include transportation fuel.

[c] Domestic production includes 800 billion cubic feet from Alaska. Other uses in this report include lease and processing plant use, transportation use, and losses during transmission and distribution.

[d] Other uses include transportation loss.

[e] Other uses in this report include pipeline fuel, transmission loss, and other transportation use. Industrial gas numbers include lease and processing plant fuel quantities.

[f] Other Uses include lease and plant fuel use and transportation loss. Refinery sector from the Annual Energy Outlook is included in Industrial Sector.

Note: Numbers may not sum to total due to independent rounding. Quantity-weighted prices were used to combine the commercial and residential sector prices contained in the EIA Annual Report and the Economic Effects Report.

See note on Table C1 for conversion factors used.

Table C3. Comparison of Various Forecasts for the Natural Gas Market in 1990 (Quantities in Quadrillion Btu; Prices in 1982 Dollars per Million Btu)

Category	EIA-GAMS[a]	AGA-TERA[b]	Alternative Report[c]	Economic Effects Report	EIA Annual Report[d]	EIA Annual Outlook[e]
Supply						
Domestic Production	18.40	18.8	18.1	--	18.1	16.4
Average Wellhead Price ...	$4.88	$3.18	$6.04	--	$7.73	$5.17
Imports and Supplemental Total	1.37	2.7	2.1	--	0.7	1.2
Total	19.73	21.5	20.2	--	18.8	17.6
Consumption						
Residential/Commercial ...	7.04	8.9	7.9	--	7.1	6.8
	$8.46	$5.82	$8.31	--	$8.31	$8.51
Industrial	6.44	9.25	7.1	--	9.1	6.0
	$6.65	$5.06	$8.31	--	$7.68	$7.17
Electric Utilities	3.38	2.6	2.7	--	2.1	2.4
	$6.03	$4.88	--	--		$7.19
Other Uses	2.86	0.8	2.5	--	0.5	2.35
Total	19.73	21.5	20.2	--	18.8	17.6

[a] Difference between total supply and total consumption includes lease and plant fuel use and transportation and distribution losses. These volumes are not modeled explicitly and so not provided.

[b] 1990 domestic production includes 820 billion cubic feet from Alaska. Prices in this report were reported in 1982 dollars. Other uses in this report include transportation fuel.

[c] Domestic production includes 800 billion cubic feet from Alaska. Other uses in this report include lease and processing plant use, transportation use, and losses during transmission and distribution.

[d] Other uses in this report include pipeline fuel, transmission loss, and other transportation use. Industrial gas numbers include lease and processing plant fuel quantities.

[e] Other uses include lease and plant fuel use and transporation loss. Refinery sector from the Annual Energy Outlook is included in Industrial Sector.

Note: Numbers may not sum to total due to independent rounding. Quantity-weighted prices were used to combine the commercial and residential sector prices contained in the EIA Annual Report and the Economic Effects Report.

See note on Table C1 for conversion factors used.

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APPENDIX D

COMPARISON OF THE NGPA AND PENDING LEGISLATION

This appendix presents a side-by-side comparison of the major provisions of the NGPA and of the following four bills currently before the 98th Congress:

- The Administration's proposal, entitled the "Natural Gas Consumer Regulatory Reform Amendments of 1983" (S. 615, introduced by Senator McClure (R-ID), and H.R. 1760, introduced by Representative Corcoran (R-IL));

- The "Natural Gas Consumer Relief Act," (H.R. 2154 introduced by Representative Gephardt (D-MO));

- The "Natural Gas Policy Act Amendments of 1983" (H.R. 1752 introduced by Representative Addabbo (D-NY), and S. 689, introduced by Senator Heinz (R-PA));

- The "Natural Gas Policy Act Reform Amendments of 1983" (H.R. 2508 introduced by Representative Slattery (D-KS)).

A brief description of other pending legislation may be found in Chapter 2.

Table D1. Comparison of Natural Gas Policy Act (NGPA) and Pending Legislation

	NGPA	Administration Proposal	Gephardt Proposal	Addabbo/Moss Proposal	Slattery Proposal
Pricing Provisions					
Contracts in Effect on Enactment					
• Ceiling Prices	NGPA price ceilings. §107 gas (except tight sands) deregulated.	§107 (tight sands) - price in effect upon date of enactment. §107 (other) - higher of price in effect upon enactment and gas cap. All other NGPA sections - lower of gas cap and NGPA ceiling. Gas cap defined as weighted average price of new and renegotiated contracts for the preceding 3 months.	January 1982 base period delivery price adjusted monthly by lower of 75 percent of change in GNP deflator or 75 percent of change in CPI energy index. §107 capped at 150 percent of §103 ceiling price. No new §107 categories. NGPA increase in §103 ceiling price for certain new onshore wells delayed to 1/1/87. Ceiling prices include all costs and profits. FERC may allow increase to recover severance taxes and processing, gathering, and transportation costs paid by seller if necessary for "just and reasonable" return.	NGPA ceiling prices with no additional inflation adjustments as of date of enactment. (§102 continues to receive 4 percent incentive adjustment.) For contracts in effect on 11/8/78, the price is rolled back to price in effect on that date unless the contract has an area rate clause specifically authorizing prices established by Congress. Ceiling prices include all costs of delivery and any other consideration received by the product.	NGPA ceiling prices.
• Decontrol Date	11/1/79 - §107 (1-4) 1/1/85 - new gas, - §102(c); new onshore production wells (§103) if not committed to interstate commerce on 4/20/77 and produced from depths greater than 5,000 feet; certain intrastate contracts for which price on 12/31/84 is greater than $1.00 per MMBtu. 7/1/87 - Any remaining §103 gas not dedicated to interstate market on 4/20/77.	NGPA decontrol schedule in effect through 12/31/85; all remaining wellhead price controls removed on 1/1/86.	Extends NGPA decontrol schedule. Gas to be decontrolled on 1/1/85 under the NGPA is decontrolled 1/1/87. Gas to be decontrolled on 7/1/87 is decontrolled on 7/1/89.	NGPA decontrol schedule.	Date of enactment for wells begun on or after enactment; new gas contracts; and gas not committed to interstate commerce on 4/20/77. NGPA date for contracts not renegotiated.
• Other			All indefinite escalators tied to other commodities are unenforceable. No FERC "just and reasonable" adjustment allowed for §104, §106, and §109, except to recover severance taxes and processing, gathering, and transportation costs paid by seller.	Indefinite price escalator clauses are null and void. FERC may adjust ceiling price to provide seller a "just and reasonable" return.	Favored nation provisions are unenforceable.

Table D1. Continued

	NGPA	Administration Proposal	Gephardt Proposal	Addabbo/Heinz Proposal	Slattery Proposal
New and Renegotiated Contracts Signed after Date of Enactment					
• Ceiling Price	Same as above	None	Same as above.	Same as above.	None.
• Decontrol Date	Same as above	New contracts—immediate decontrol. Renegotiated contracts—decontrol upon renegotiation.	Same as above.	Same as above.	New contracts including those resulting from market-out actions are immediately decontrolled. Renegotiated contracts involving S102(c and d), S107, S103 (not dedicated to interstate commerce on 4/20/77)—decontrol upon renegotiation.
Take-or-Pay Percentage Allowed	Not Addressed.	Pipelines may reduce takes to 70 percent of deliverability (AD gas not included in this coverage).	Pipelines may reduce takes of S102, S103, S107, and S108 gas to 50 percent of the annual contract quantity.	Take-or-pay in all contracts (for first sale of gas) in effect on enactment limited to 50 percent.	Take-or-pay in contracts for first sale unenforceable in excess if 50 percent of deliverability. (AD gas and S108 gas not included in this coverage.)
Length of Time These Restrictions Are in Effect		Expires 1/1/86.	3 years from date of enactment.	No limit.	3 years from date of enactment.
Other		This does not apply to contracts signed or renegotiated after enactment. Rate of take for own or affiliates' gas may not be higher than for less expensive gas. Take for AD gas is 100 percent.			Take-or-pay provisions which preclude make-up or do not allow refund for gas not taken are not enforceable. If volumes taken are reduced by pipeline, FERC must adjust other contracts for resale of gas to a degree which corresponds to reduced volumes. This is not to require an increase in minimum bill requirements.

Table D1. Continued

	NGPA	Administration Proposal	Gephardt Proposal	Addabbo/Heinz Proposal	Slattery Proposal
Contract Renegotiation	Not addressed.	Any contract may be renegotiated and operate by the new terms.	Pipeline may submit request to seller to renegotiate contract.		
Market-Out	Not addressed.	On 1/1/85, for any contract that has not been renegotiated, either party may market-out.	Pipeline may market out of any contract not renegotiated within 30 days of request. Higher priced contracts, starting with affiliates' contracts, must be acted on first. No new contract gas can be purchased at a higher price than the market-out price. Each category of gas is considered a separate contract for this provision.	All 102/103/107 contracts deemed to have market-out clauses. Either party may offer a new contract price and may market-out if not accepted within 30 days.	Provides market-out for S102(c&d), S107, and S103 (not dedicated to interstate commerce on 4/20/77), excluding warranty contracts. Market-out authority is in effect for one year, may be excised only once and requires 45 days notice. Seller may obtain alternate purchaser (other than an affiliate). Gas subject to abandonment requirements of NGA may not be sold to alternate purchaser without FERC approval.
Right of First Refusal	Not Addressed.	None	Purchaser is given right of first refusal in any market-out action.	Purchaser is given right of first refusal in any market-out action.	Purchaser given right of first refusal in any market-out action.

Table D1. Continued

	NGPA	Administration Proposal	Gephardt Proposal	Addabbo/Heinz Proposal	Slattery Proposal
Contract Carriage	Commission given authority to authorize pipelines to transport gas for a "just and reasonable" return under the NGA.	Pipeline must transport gas not taken due to reduction in take-or-pay at $.05 per MMBtu plus cost. Under certain conditions FERC may require a pipeline to transport gas at $.05 per MMBtu plus cost.	Pipeline must transport gas not taken under reduction in take-or-pay. FERC may order pipeline to transport gas under certain circumstances (does not cover application for affiliated producers) if there is available capacity, no new construction required, and no impairment of of service to existing or future non-interruptible customers. Compensation to be "just and reasonable" under terms of NGA. Intrastate companies do not become jurisdictional under NGA if required by FERC to transport gas.	Pipeline must transport any gas released under market out provision or if required by FERC at a "just and reasonable" rate.	Pipeline obligated to transport gas released under market out action on a best efforts basis. This must not impair service to customers, will extend only to facilities of original purchaser, and will remain in effect only for duration of original contract. FERC may terminate carriage if disruptive to system or found contrary to public interest. FERC to publish notice of transportation agreements. FERC to prescribe an incentive rate. Compensation to be rate agreed by parties, or if not agreed prescribed by FERC. Revenues above cost to be credited to customers.
Imports	Not addressed.	Not addressed.	Capped at 150 percent of Section 103 price ceiling.	Not addressed.	Requires study of import contracts to ensure they are consistent with the public interest.
Pipeline Pass-through Limitations	Requires FERC to allow pass-through of purchased gas costs determined to be just and reasonable as defined by the NGPA; that is, do not exceed the maximum lawful price. FERC may disallow if it finds that amounts were excessive due to fraud, abuse or similar grounds.	Interstate pipelines not allowed to immediately pass through purchased gas costs above their last pre-enactment level plus inflation. Any additional cost must be approved by FERC after public proceeding if it finds the costs were just and reasonable, and prudently incurred. This limitation expires on 1/1/86.	Expands FERC authority to disallow charges if the pipeline has failed to minimize gas costs.	Reaffirms FERC authority with respect to sections 4 and 5 of the NGA.	FERC to establish standards of prudent purchasing practices. For new and renegotiated contracts, FERC may disallow costs considered excessive. FERC may disallow excessive cost for existing contracts after public hearing.

Table D1. Continued

	NGPA	Administration Proposal	Gephardt Proposal	Addabbo/Weinz Proposal	Slattery Proposal
Minimum Commodity Bills	Not addressed.	Not addressed.	Minimum bills above 50 percent of maximum annual volume or those without make-up provisions are unenforceable.	Requires comprehensive minimum bill financing and price responsiveness study within one year.	(See take-or-pay).
Other		Repeals authority to reimpose controls; incremental pricing; and the Fuel Use Act. Gas is removed from non-price regulations of NGA and NGPA on 1/1/85, or on renegotiation if before then. All buyers given equal access to offshore and interstate gas.	All contracts to be filed with FERC. FERC required to make ruling within a year on standards for interstate pipeline tariffs.	All contracts to be filed with FERC. Interest rate on any pipeline collections subject to refund to be prime plus no less than 3 points.	Repeals Fuel Use Act restrictions on new and existing major fuel burning installations, boilers for space heating and outdoor lighting. Also provides an exemption for new power plants to burn gas for clean air. Repeals incremental pricing.

Report of the Electricity Policy Project

The Future of Electric Power in America: Economic Supply for Economic Growth

June 1983

U.S. Department of Energy
Office of Policy, Planning and Analysis
Washington, D.C. 20585

EXECUTIVE SUMMARY

I. INTRODUCTION

Electricity in all parts of the country and in all sectors of the economy--industrial, commercial, and residential--is the lifeblood of the nation. The pervasive and expanding use of electricity is reflected in its growing share of the total energy used in the U.S. economy. For this reason, if electricity were ever in short supply or unreasonably expensive, this nation would suffer immeasurably. Consumers would be forced to spend a larger portion of their budgets for a less reliable electric supply system, and the competitive position of U.S. products in world markets would decline. New industry might be forced to locate abroad and thereby adversely affect employment and overall economic activity.

There is little disagreement that electricity is a fundamental and expanding part of our nation's economic infrastructure. There is also little disagreement that the last ten years have been a period of tumultuous change for this industry. In the 1970s, after decades of strong demand growth and stable or declining prices, the industry began experiencing a decline in demand growth rates and an increase in the cost of electric production. The institutions involved in electric power markets have been strained by these and other radical changes in their environment. Rate regulation has evolved from a rather simple and agreeable process which benignly approved regular decreases in electric rates to a complex, highly contentious undertaking required to balance the economic interests of contending parties in the face of increasing costs. The public has come to regard the electric power industry with suspicion and with less respect than the industry had long enjoyed. The interruption of long-standing industry practices and expectations has also greatly sensitized its leadership to future uncertainties.

This report focuses on the current and prospective condition of electric power markets in the United States and evaluates the prospects for long-term sufficiency and efficiency of electric power supplies. A later volume will deal with possible "prescriptions" which could be pursued by the Federal Government to improve the market efficiency of the electric power industry.

II. ELECTRIC DEMAND (Chapter 3)

The growth in electricity demand has consistently outpaced GNP growth. For example, it grew 1.7 times faster than GNP during the 1960-1973 period and 1.2 times faster during the 1973-1980 period. By contrast, non-electric energy demand grew at about 0.8 times GNP growth during the 1960-1973 period and has actually declined slightly since 1973, despite GNP growth averaging 2.35 percent per year. The cumulative effect of these trends has been a substantial increase in the electric intensity of the economy and an increase in the share of electricity in the delivered energy market; these trends are expected to continue. Many people are aware that the nation has managed to sustain economic growth since the oil embargo of 1973 without corresponding increases in total energy consumption, but they fail to realize that electric demand has continued to increase since then. This is a critical misunderstanding.

Much of the difference between historic patterns of electric demand and non-electric energy demand can be readily explained by energy prices. Those who assume that electric prices have behaved like non-electric energy prices are unaware of an important distinction between different energy forms. All energy forms experienced declines in real (i.e., inflation-adjusted) prices through the early 1970s, although electric prices declined more rapidly than those of other energy forms. After the 1973 embargo, all energy forms experienced dramatic increases in real prices, with the result that the real price of aggregate energy in 1980 was twice the price in 1960. However, the increases in electric prices have been very much less than those for other energy forms. In fact, the prices for electricity in 1980 were no higher than they were in 1960 in real terms. This difference in the rate of price increases would obviously explain a great deal of the difference in demand patterns between electricity and all other energy forms. Future electric prices are expected to continue to be relatively stable in most regions; however, in regions where electricity is generated from natural gas (the Southwest) or old hydro-electric facilities (the Pacific Northwest) and has been relatively inexpensive, real electric prices will rise substantially from their low historical base through the remainder of this decade.

There have also been substantial differences in electric prices in different sectors of the economy, namely, the residential, commercial, and industrial sectors. For example, a large share of the burden of increased electric costs in the 1970s was borne by industrial consumers. During the 1973-1980 period, electric prices increased on average about forty percent in real terms, but industrial electricity prices doubled.

The analysis of future electric demand undertaken for this project involved projections to 1990 and 2000 by varying assumptions about key variables, including GNP growth, world oil prices, and price elasticity of energy demand; a review of several recent projections indicating relatively low electric demand; a review of the electric demand prospects in the residential, commercial, and industrial sectors; and a review of the relationship between electric energy demand growth rates and peak demand growth rates.

The general conclusion of this analysis in national terms is that, even with continued improvements in end-use efficiency, electric demand can be expected to continue to grow at a rate at least equal to the growth of the nation's economy throughout the remainder of this century. By contrast, demand for other fuel forms, particularly oil and gas, is expected to grow at a much slower pace, if not actually decline. A national average growth rate of three percent per year was selected as a reasonable median estimate of future electric demand growth corresponding to the assumed level of expected growth in the economy. Higher (4%) and lower (2%) estimates of electric demand growth were also developed to reflect uncertainties over demand growth, expanded conservation efforts, substitution of electricity for other fuels, changing product mixes in the economy, and the like.

Several "low demand" studies were reviewed to understand why they yielded substantially different projections of future electricity demand. These studies do not project a continuation of the trend which has been experienced through much of the twentieth century and now appears likely to continue through 2000: namely, that the economy is very likely to turn increasingly to electricity for its energy requirements even though higher energy prices may somewhat abate the demand for energy.

The review of these "low demand" studies indicates that the differences between their electric demand projections and ours did not result from radically different projections of GNP growth or aggregate energy prices. Instead, the differences were a result of different assumptions about electric prices and the cross-price effects on demand. The "low demand" studies assume electric prices high in relation to other energy prices and a relatively low propensity on the consumers' part to substitute electricity for other energy forms in response to differential price changes.

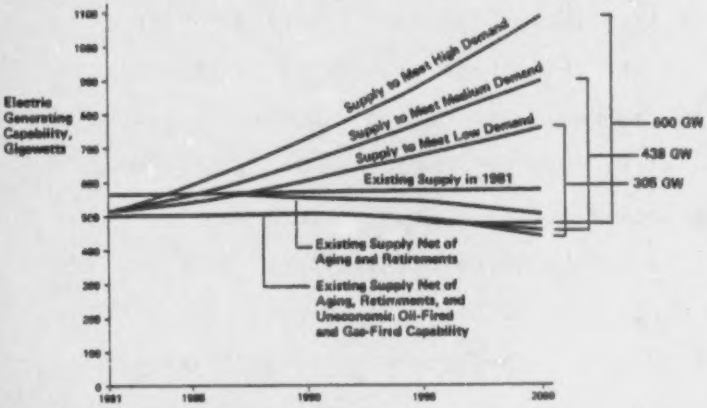
III. ELECTRIC SUPPLY (Chapter 4)

Three primary factors create a need for new power plants: (1) demand growth, (2) retirements and declining performance of existing units, and (3) the opportunity for displacement of high-cost fuels.

Different projected levels of demand through 2000 require different levels of electric generating capability in order to ensure reliable electric service in the future, as shown in Figure ES-1.

Figure ES-1

Electric Supply Required to Meet Different Levels of Electric Demand, Compared with Existing Supply Net of Aging, Retirements, Uneconomic Capability



High Demand = 4 Percent Annual Growth in Peak Load
Medium Demand = 3 Percent Annual Growth in Peak Load
Low Demand = 2 Percent Annual Growth in Peak Load

The medium demand growth rate, which represents 3 percent growth per year, shows a requirement for an additional 438 gigawatts (a gigawatt is 1000 megawatts) of new generating capability by 2000. This requirement compares to an existing national generating capability in 1981 of 572 gigawatts. About 75 percent (329 GW) of this requirement for new generation is due to increased demand, 15 percent (71 GW) is required to replace capacity lost due to retirements and declining performance, and the remaining 10 percent (38 GW) is required to displace high-cost fuels.

The requirement for this additional capability of 438 gigawatts includes provision for a reserve margin of 20 percent, a widely accepted industry standard. Since reserve margins in the 1980s have been 30 to 35 percent, it would appear that, as many allege, the industry is overbuilt. However, when existing supply is adjusted to eliminate economically obsolete generation, the current level of supply turns out to be about the correct level both to ensure reliable supply and to displace uneconomic supply. It should be noted that, although the national level of supply is approximately correct, the location of this supply is not; some regions have excess supply with limited remaining opportunities to displace oil or gas, while other regions have substantial levels of oil and gas but insufficient capacity to displace it.

A comparison of the future supply requirements of the electric power industry and the supply plans of the industry as reported to the North American Electric Reliability Council (NERC), shows that, with medium demand growth (3%/yr.), current supply plans will be deficient nationally on an economic basis beginning in 1989. If economic oil and gas displacement is ignored, current generation plans become inadequate nationally by 1993.

The NERC supply projections must be qualified. Of the 152 gigawatts of new capacity which NERC projects will be in service by 1990, only about 107 gigawatts is sufficiently under way that timely completion is likely. Given the trends in cancellations and delays of new construction, much of the remaining 45 gigawatts of planned generation cannot be realistically expected to be in service on schedule. If most of this capacity is not available on schedule, reliable electric service will be jeopardized in much of the nation by 1990. In some regions, reserve margins would drop below ten percent.

In the late 1960s and early 1970s, national average reserve margins fell below the twenty-percent level considered necessary to maintain reliable service because of strong demand growth and delays in the construction of new supply. During this period, the industry purchased and installed some 35 gigawatts of combustion turbines in order to ensure reliable service. Such turbines can be built and installed quickly at low capital costs. Unfortunately, they are relatively inefficient, can be fueled only by oil and natural gas, and, since 1973, have been very expensive to run. Such stop-gap measures would again be available to the industry with any future supply shortfalls (after modification of some existing federal laws) to ensure reliable supply. However, the cost of such a supply strategy over the long term is substantially higher electric prices and higher oil imports.

IV. THE ECONOMICS OF ELECTRICITY (Chapter 5)

Even though electricity is the most capital-intensive industry in the economy and the costs of new power plants have increased substantially over the past decade, the trend over the past ten years has been for the electric utility industry to become substantially less capital-intensive. That is to say, capital-related costs have become a smaller fraction of total costs. The capital-related components of costs (including taxes) have decreased from nearly 60 percent of total costs in the early 1970s to less than 40 percent of total costs by 1980. During the same period, fuel costs have increased from around 15 percent of total costs in 1970 to over 35 percent in 1980.

What is true about the effect of fuel costs on national electric prices is only partly true of regional electric prices. For perhaps no other commodity in the nation's economy exhibits as much regional variation in price as does electricity. For example, in the 1973-1981 period, while the national average price of electricity was increasing by a cumulative total of 38 percent in real terms, the prices for customers on most coal-based systems increased at a lesser rate. Meanwhile, the prices for some oil-based utilities were increasing by more than 100 percent in real terms during this period.

There is a broad public perception that constructing new coal-fired and nuclear facilities substantially increases the price of electricity. But the experience of the past two decades suggests otherwise. For oil-based utilities, new coal-fired and nuclear facilities have mitigated rate increases. For coal-fired/nuclear utilities, new generation did not reduce costs, but new construction was not the most significant cause of rate increases.

The "death spiral" hypothesis or "spiral of impossibility" was found to be insupportable. This hypothesis suggests that overbuilding utility systems drives up electricity prices, thus depresses demand, thus drives prices up even further, and so on, until the utilities are eventually bankrupted. However, although many utilities have been substantially "overbuilt" in recent years, the price impacts of overbuilding are minor compared to the price impacts of continuing to use oil. Electricity sales by virtually all utilities in the U.S., including many with the largest price increases (caused by the use of oil rather than overbuilding) have continued to grow over the past decade, contrary to the "death spiral" hypothesis.

The lower price trajectories now projected for oil and gas raise the question whether displacement of oil and gas from baseload generation is still economically advantageous. However, there still remains a substantial economic benefit from displacing oil or natural gas as a baseload generation fuel with either new coal-fired or nuclear facilities.

The failure to take advantage of this opportunity to displace oil and gas can be expensive, but many decisions are currently being made which do exactly this. For example, over 200 delays or cancellations of new coal-fired or nuclear facilities were announced in 1980 and 1981. As many as half of these plants could reduce the cost of electricity by displacing high-cost fuels, and their delay or cancellation will thereby cause electric prices to be higher than necessary. In fact, it is estimated that these delays and cancellations in that two-year period alone will cause consumers to pay $20 billion more for electricity (in net present value, 1982$) over the remainder of this century.

Annual electric bills could be as much as $18 billion higher by 2000 if utilities pursue supply strategies intended only to minimize their capital expenditures. Thus, failure to pursue economic investments in new supply will have a substantial adverse impact on electric prices while, at the same time, increasing oil import levels and serving as a damper on economic growth.

The additional costs to consumers of an improved rate regulatory process which would enable utilities to build economically efficient capacity are modest. Increased rates to improve the financial condition of the industry and thereby encourage construction would involve increases in electric prices averaging only five to six percent. These increased costs are more than offset by savings which yield a rate of return to consumers ranging between sixteen and forty percent over the long term. Accordingly, consumers would be well served by "investing" in the improved financial performance of their utility company. Their "investment" in near-term electric price increases would be handsomely compensated by longer-term rate reductions.

V. FINANCING AND REGULATING THE U.S. ELECTRIC SYSTEM (Chapter 6)

The willingness of individual utilities to invest in additional electric system facilities is inseparably linked to their expectations about future power needs and the regulatory climate. Although utility managers may perceive the need to make additional investments, it would be imprudent of them to make those investments if they do not believe that the regulatory process will permit them to earn adequate and timely returns. Accordingly, the regulatory process through rate-setting (as well as health, safety, and environmental permitting) has the ability to stimulate or retard new investment needed to reliably satisfy load growth or to reduce production costs.

The total cumulative capital investment required by the electric utility industry through 2000 is approximately $1 trillion when measured in constant 1982 dollars ($1.8 trillion at a 5% rate of inflation). By comparison, the total existing asset base of the electric power industry (both public and private) in 1981 was about $300 billion. Thus, the investment required at a three percent rate of load growth through 2000 is roughly six times as great, in nominal terms, as the utility investment already in place.

Whether utilities can finance the expansion that is needed for reliable economic service depends on the answers to two questions: first, whether the industry's financial requirements will absorb such a large fraction of the nation's available investment capital that it will crowd out other investors and thus adversely affect other segments of the economy; and second, whether it is reasonable to assume that the industry has both the capability and incentives to raise the funds in financial markets necessary to build these new facilities.

In response to the first issue, these future capital requirements for the electric utility industry will not require the industry to claim a larger fraction of gross domestic private investment than it has historically. Although the investment needs of this industry throughout the remainder of this century are very large, they are not out of proportion to the historical levels of capital which this industry has required. Thus, it is unreasonable to assume that the electric utility industry will crowd out other capital investment as it pursues the capital it needs to ensure adequate future electric supplies at minimum cost.

Whether the industry will have the ability or willingness to pursue the investment is a separate question. For many people it is difficult to believe that the electric utility industry would be disinclined to pursue required capital investment. The industry has long had a reputation for over-investment, which appears substantiated by the high reserve margins which exist in many parts of the country today.

There has been a long-standing theory that because utility profits are earned as an allowed rate of return on capital investments, utilities would tend to over-invest in order to maximize profits. This theory, referred to as the Averch-Johnson, or A-J, effect (named for the economists who developed it) has been widely accepted as an accurate description of industry behavior.

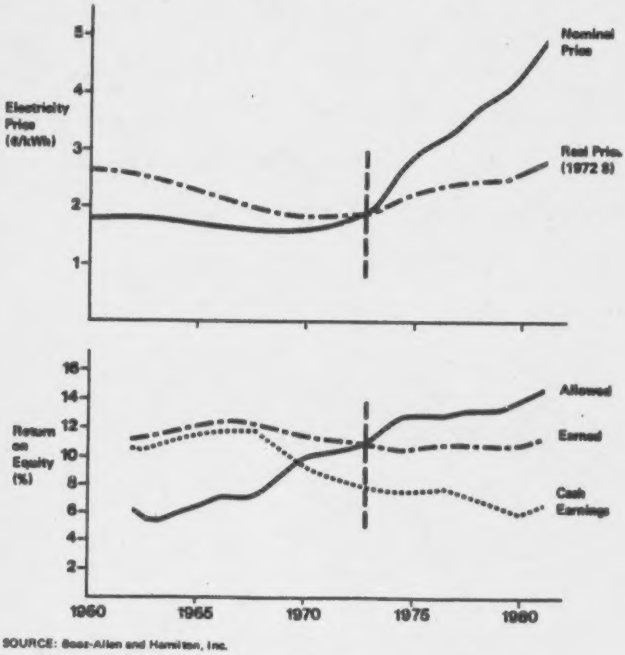
A look at historic rates of return in this industry tends to support the A-J theory at the time it was developed, in the early 1960s. During this period, when electricity rates were constant or declining, the electric utility industry was actually earning returns well in excess of the authorized returns being set by the regulatory process. These excess earnings were in large part created by the intrinsic nature of regulation, particularly the phenomenon known as "regulatory lag." In essence, "regulatory lag" reflects the fact that electricity rates are generally set on a historic basis. If costs are declining, as they were in the 1960s, regulatory lag would cause rates to be too high and the excess would accrue to the benefit of the utility investor.

However, the business environment changed radically for the electric utility industry in the early 1970s. Maturation of the industry's technology reduced or eliminated the cost reductions which had been routine for decades. Simultaneously, inflation and other factors started raising costs, especially fuel costs, at a rapid pace. As a result, electric rates started going up for the first time in the industry's history.

With costs increasing instead of decreasing, the same regulatory treatment which yielded excess returns to the industry in the 1960s started causing realized returns to lag behind authorized returns. This phenomenon is termed "attrition" and has persisted in the industry from the early 1970s through the present. Attrition has turned the A-J effect upside-down. Instead of earning excess returns, the industry has been systematically under-recovering investment costs for the past ten years. The incentives for over-investment which persisted for decades and were identified in the A-J treatise have now been replaced with reverse incentives to under-invest. The effect of regulatory lag on prices and earnings since 1960 is shown in Figure ES-2.

Figure ES-2

Historical Electric Prices and Rates of Return on Electric Utility Equity



SOURCE: Booz-Allen and Hamilton, Inc.

The non-cash earnings represent an "Allowance for Funds Used During Construction" (AFUDC), a regulatory artifact which represents earnings paid in cash only when a facility is placed into service. Increased costs of new generation facilities and lengthened construction periods have caused AFUDC to grow to over half of current earnings for the industry overall. Since these are not cash earnings, this represents a substantial decline in the quality of industry earnings, which has not been ignored by the banking or investment community.

This decline in the financial condition of the electric utility industry is reflected in the aggregate financial statistics of the industry. For example, the market-to-book ratio (the market value of equity divided by its book, or accounting, value) fell below a value of 1.0 in 1974, and has remained below 1.0 ever since. Other key financial indices have displayed a similar pattern of decline over the past two decades.

Recently, however, several financial measures of the electric utility industry have improved. In 1981, over $8 billion in base rate relief was awarded, and the authorized rate of return exceeded fifteen percent in both 1981 and 1982.

Interest coverage ratios have improved modestly, a number of companies are currently enjoying market-to-book ratios in excess of 1.0, and the erosion in utility bond ratings has slowed. Some observers regard these positive signs in utility financial performance as an indication that the industry is recovering from a difficult decade of adjustment, and they are particularly hopeful that the regulatory process has now adjusted to the changing environment which the industry faces and is now pursuing regulatory policies ensuring that the industry has the proper incentives to pursue all necessary and prudent capital investment.

This conclusion is too sanguine, for the industry still faces substantial financial disincentives for new investment. First, attrition persists; the industry continues to experience realized returns well below allowed returns. Second, the quality of earnings remains poor; no other major industry has so low a fraction of cash earnings to total earnings. Third, bond ratings remain substantially depressed, and there were still more bond downgradings than upgradings in 1982. Fourth, although showing some improvement in the last year, the market-to-book ratio of the industry is only forty percent of the level it attained in the 1960s. Finally, since the industry is realizing cash earnings which are only about sixty percent of dividends paid to investors, substantial amounts of cash flow from depreciation are being paid out to investors rather than being reinvested to replace aging facilities.

But this discussion of aggregate financial statistics distracts attention from the most important financial fact facing this industry: as a general rule, new investment can be expected to depress most financial parameters of a typical utility company, especially during the construction period. Thus, no matter how financially healthy a utility company is, there will be a powerful incentive to minimize investment. In fact, reducing construction programs and the associated capital requirements is a good way for a utility manager to improve his company's financial performance. The recent improvement in utility financial indicators is at least in part attributable to the reductions in construction plans which have been prevalent over the past few years. The ultimate adverse impacts of such strategies on electric power sufficiency and efficiency are obvious.

In short, the capital requirements for the electric utility industry in the future will continue to be quite large. In the 1960s, the financial incentives for the industry were well aligned with its financial needs. However, since the early 1970s, these incentives have been transformed. As a result, the industry has reduced its supply plans in response to reduced demand and financial disincentives for new investment. The excess capacity which has existed since 1974 has inadvertently created a "grace period" for the industry. However, even with modest levels of projected demand growth, this "grace period" is coming to an end.

VI. PERCEPTIONS OF THE U.S. ELECTRIC SYSTEM (Chapter 7)

The fact that electricity prices are set by public officials and not a market makes the electric industry very sensitive to public perceptions and attitudes. The majority of consumers believes that electricity is a "right", like clean air or water. Accordingly, they take for granted that electricity will be available when they want it and are primarily concerned with the price of electricity and the size of their bills. In some parts of the country, consumers are actively pressuring regulators to restrain electricity prices and appear indifferent to the long-term consequences. Thus, there is little public concern for future electric supply; although some Americans think their utility needs to build more plants, most Americans think that future electric supply will be adequate without significant new plant construction. If they think new plants are needed, they also tend to believe that utilities can readily obtain the necessary capital to build new plants. They do not agree that the utilities have financial problems.

Unfortunately, public confidence in the electric industry and the regulatory system has deteriorated over the past ten years as electricity prices have gone up. There is a growing perception that utility companies are not as well managed as they could be nor as well regulated as they should be. Increasingly, the public believes that public utility commissions (PUCs) favor utility interests over customer interests in setting rates. To a great extent, this view may reflect a general lack of public familiarity with PUCs, their membership, qualifications, and hearing proceedings.

Two related opinions held by a majority of Americans should be kept in mind as the implications of these attitudes are assessed. First, the significance of OPEC as a threat to electric availability, reliability, and price, and to U.S.

national security has significantly lessened over the past two years. Second, nuclear energy continues to divide Americans. There is significant public concern that utilities have not been honest with the public about nuclear costs or safety and that the quality of construction of new nuclear plants is less than good.

The perceptions of utility management on the general circumstances facing their industry are more diverse. In large part, the variety of perceptions reflects the different circumstances facing individual companies in such areas as rate regulation, demand growth, and the size of construction programs. However, most utility managers would agree that, over the past ten years, the industry has been put in a difficult position in attempting to balance the interests of their investors and their consumers. Before the early 1970s, this task was simple; however, as electricity costs have increased over the past decade, the interests of these two groups have diverged widely, and utility management is caught in the middle.

Regulators are caught in the middle of conflicting interests of consumers and investors in much the same way as the utility companies. In some respects, the problem for regulators is even greater since they have other competing interests to adjudicate, such as those between one consumer class and another (e.g., residential vs. industrial) or between today's ratepayer and tomorrow's.

A recent resolution passed by the National Governor's Association (NGA) called for major reforms in state regulation of electricity. The resolution seeks federal legislation to enable states to join together to obtain a regional perspective on utility planning and system coordination, and to provide for more efficient system design and operation. The NGA proposal reflects the fact that state authorities realize that substantial structural reform of electric power regulation may be required to ensure the long-term sufficiency and efficiency of electric supplies.

VII. GENERAL CONCLUSIONS

The fact that electric power supply in the U.S. has for decades been a model of reliability and efficiency does not ensure the industry's ability to continue to provide adequate future supplies at minimum cost. The past decade has been a period of tumultuous change for the industry, its regulators, and the consumers of electric power and has increased confusion, anxiety, and even hostility among all parties.

The substantial conservation of electricity which has occurred since the early 1970s has deferred the day of reckoning in electric power. But the current excess of reserve capacity is likely to disappear by the end of the decade and leave utility managers and regulators in the difficult position of having to decide whose interests to protect.

The institutions which produce and regulate electric power have had a difficult time adjusting to the post-embargo economics of electric power. They have been forced into the tortuous process of trading-off the interests of various parties, such as consumers and investors or different classes of consumers, in a process which has increasingly de-emphasized the long-term economic consequences of today's decisions. In this contentious regulatory environment, assurance of sufficient long-term electric supplies and improvements in economic efficiency have become issues which are subordinated to near-term issues of price and equity--who pays what part of today's increasing cost. If this situation continues, the inevitable result is likely to be a less reliable, higher-cost electric system. Given the increasing importance of electricity as part of our nation's energy infrastructure, such a decline would have ominous implications for national economic growth for the remainder of this century.

We recognize that there is a diversity of views and circumstances within the industry as well as among state and local jurisdictions which have regulatory authority over the electric utility industry. For that reason, the conclusions in this report are intended to provide a springboard for discussion and debate on the critical issues affecting electricity in this country. Such a discussion must recognize the uncertainties inherent in our economy and the strong role that state and local governments have traditionally played in resolving these uncertainties in connection with the regulation of electric power. A healthy diversity of perspectives on electricity issues is essential if the industry, the general public, and the regulators are to be adequately prepared for the challenges that lie ahead.

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REVIEW OF POST-2000
ENERGY PROJECTIONS

FINAL REPORT
(July 1982—October 1982)

Gas Research Institute
8600 West Bryn Mawr Avenue
Chicago, Illinois 60631

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Prepared by

Joel Darmstadter, Douglas McDonald and Michael Coda

Resources for the Future
1755 Massachusetts Avenue, N.W.
Washington, D.C. 20036

For

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Strategic Analysis and Energy Forecasting Division

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16. Abstract (Limit: 200 words)

This report reviews a selected number of projections of U.S. energy consumption that span a period going beyond the year 2000. The review is designed to provide part of the framework within which technology planning for the early part of the 21st century must be cast. The review confirms the expectation that successive long-term projections for a given year in the future have been significantly reduced. Among primary energy sources, conventional oil and gas are estimated, in most of the studies, to significantly diminish their absolute and relative importance, while coal and nuclear power substantially increase theirs. Synthetic liquid and gaseous fuels account for a large part of incremental energy consumption to the 2020-2025 period as does--to a somewhat lesser extent--energy delivered in the form of electricity. Renewables are given surprisingly little weight in most of the studies: and new "backstop" technologies tend to be incorporated into future energy balances in a narrowly-focused, price-deterministic framework. In both cases uncertainty may be so great as to make attempts at quantitative estimation a fairly elusive task. The prospects for these two categories may not be adequately captured--and is perhaps understated--in statistical forecasts.

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Title	Review of Post-2000 Energy Projections
Contractor	Resources for the Future GRI Contract Number: 5082-711-0639
Principal Investigators	Joel Darmstadter, Douglas McDonald, and Michael Coda
Report Period	July 1982-October 1982 Final Report
Objective	The project sought to provide a descriptive and critical survey of U.S. energy projections beyond the year 2000.
Technical Perspective	Many current and imminent decisions regarding R&D, technology, and investment depend on assumptions regarding energy demand and supply conditions prevailing in the post-2000 period. This review and analysis of studies containing energy projections beyond 2000 is designed to improve long-term strategic planning.
Results	The review confirms the expectation that successive long-term projections for a given year in the future have been significantly reduced. Among primary energy sources, conventional oil and gas are estimated to decline absolutely and relatively; the converse is true of coal and nuclear. Synthetic liquid and gaseous fuels account for a large part of incremental energy requirements to the 2000-2025 period, as does energy delivered in the form of electricity. While recognizing the usefulness and necessity of such long-term studies, the authors discuss as well their weaknesses and limitations.
Technical Approach	The report surveys, and describes in detail, a number of major long-term energy models and projections prepared within the last five years. A set of comparative tables and accompanying text enable the reader to discern the principal features and distinguishing characteristics of the different studies and models examined. However, no attempt was made to manipulate the different models--for example, in order to test the effect of imposing uniform assumptions.

Project Implications

The project has provided a comprehensive survey of recent post-2000 energy projections as well as the methods used to obtain them. This project will provide GRI an information base from which it can begin to analyze post-2000 energy trends in order to incorporate such long-term trends into its R&D planning when necessary.

GRI Project Manager
Thomas J. Woods
Senior Energy Analyst

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PART ONE: MAJOR HIGHLIGHTS

INTRODUCTION AND BACKGROUND

During the decade of the 1970s, the forecasting of long-term energy requirements approached the dimensions of a national obsession. There were probably two reasons for this development. One was the oil price shock of 1973-74 which, along with its reverberations to other energy sectors, seemed to portend disturbances and discontinuity in the growth and structure of the economy, in technology, and in personal well-being. The second reason for the outpouring of energy projections had a more ideological aspect. The rapidly growing concern with quality of life focused on future energy growth as a tangible as well as symbolic threat to environmental and ecological integrity.

The fact that most of the energy projections which were developed looked ahead only to the year 2000 may seem curious--given the underlying reasons for worrying about the long-term energy future in the first place--but is really not hard to explain. For one thing, the millenium was an inviting milestone for energy as well as many other numerical targets. More importantly, deficiencies of method and data and uncertainty surrounding technological and policy trends properly dictated restraint in efforts put a numerical stamp on developments more than one or two decades hence. Indeed, even attempts at credible projections of energy trends out to the year 2000 are fraught with considerable difficulty, since the statistical analysis is called upon to generate outcomes and relationships based on historical data and information widely recognized to be inadequate. Trying to gauge the demand and supply impacts of rising real energy prices when most of our historical experience has been with stable or declining prices is the most pointed example of the problem.

These deficiencies having been noted, the fact remains that, however tenuous, energy projections covering a 30-40-50 year time path serve an important need. The planning and construction lead-time added to the life expectancy of certain capital facilities take us well beyond the turn of the century. Today's R&D decisions frequently relate to technologies which may become commercial on an equally distant time scale. Energy-related environmental perturbations, and means to deal with them, compel us to consider alternative energy supply-demand trajectories to the middle of the 21st century.

It is in connection with such concerns that the present survey accords attention to a longer-than-usual time span. This document examines the principal features and findings of a series of studies which include U.S. energy projections going beyond the year 2000. Our detailed account of the various studies analyzed will be found in the set of appendices that make up the bulk of this report. In this--more general--main section, we review and comment on the major results of the studies surveyed in a broad comparative perspective. While a number of studies generate, as is only appropriate, alternative "cases" or "scenarios" based on alternative economic, technological, and policy assumptions, this section highlights, in most instances, that set of projections variously labeled "base-case", "baseline", "mid-point", "mid-range", "most probable" or by still some other designation. Where a particular study did not give such a baseline projection, we presumed to fashion one from the outer ranges provided.

We reviewed seven post-2000 energy projections, described and documented in Appendices A through G:

- o ETA/MACRO - an integrated model of energy-economy relations developed by Alan Manne of Stanford University.
- o LEAP - the Energy Information Administration's (EIA) "Long-Term Energy Analysis Program" model, a highly detailed dynamic representation of energy supply, conversion, and demand.
- o ORNL - the results of Oak Ridge National Laboratory's (ORNL) National Energy Perspective study, undertaken to guide ORNL in establishing priorities for research and development over the coming years, and based on a blend of trend analysis and specification of a set of planning objectives.

- IEA/ORAU - part of a long-term global framework for energy assessment developed by the Institute for Energy Analysis (of Oak Ridge Associated Universities) and designed to study the implications of carbon dioxide accumulation in the atmosphere.
- CONAES - analysis by the Demand and Conservation Panel of the National Research Council's Committee on Nuclear and Alternative Energy Systems which combined sectoral demand scenarios with econometric modeling and explored variability in energy use at given GNP levels.
- RFF/SEAS - An adaptation by authors at Resources for the Future of a "Strategic Environmental Assessent System," which, among other complex features, utilizes a dynamic input-output forecasting model.
- STANFORD/IES - an effort, by Stanford University's Institute for Energy Studies, to quantify the energy implications of emerging value systems and other characteristics of socio-economic development. (This study does not lend itself to ready comparison with the preceding six studies and so is commented upon separately.)

In addition to our review of the projections developed in these detailed studies, it was possible to consult the results of five more aggregative forecasting efforts. Two of these (known as the BNL/DJA and Fossil-2 models) were taken from a DOE comparative assessment which ran several models under a set of common assumptions. The other three (DESOM, SRI, and Nordhaus models) were taken from a similar assessment done for the CONAES.[1]

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[1] The DOE assessment appears in Andy S. Kydes and John D. Pierson, "A Comparative Assessment of Five Long-Run Energy Projections," Report to the Energy Information Administration, U.S. Department of Energy, 1979. The CONAES assessment appears in National Academy of Sciences, "Energy Modeling for an Uncertain Future," Report of the Modeling Group Synthesis Panel of the Committee on Nuclear and Alternative Energy Systems, Supporting Paper No. 2, 1978.

The acronyms cited in the text above are defined as follows: BNL/DJA = Brookhaven National Laboratory/Dale Jorgenson Associates, DESOM = Dynamic Energy System Optimization Model, and SRI = Stanford Research Institute (not to be confused with the Stanford Research Institute study referred to earlier and described in Appendix F). "Nordhaus" refers to Prof. William Nordhaus of Yale University, and "Fossil-2" refers to a systems dynamics simulation model designed to evaluate the potential magnitude of the U.S. energy problem and to assess the impact of various policy options on the U.S. energy system.

PRINCIPAL COMPARATIVE RESULTS

Aggregate Energy Consumption

Table 1 presents a comprehensive picture of comparative results in three basic indicators (primary energy consumption, GNP, and energy consumption per dollar of GNP) for benchmark years in the future between 1985 and 2050.

In order to facilitate comparison among, and extract key findings from, the various studies listed in Table 1, let us turn next to table 2. Here we present comparative projects, for the year 2020, of the three indicators shown in Table 1. For studies lacking data for 2020, we relied on extrapolation and interpolation to provide an estimate. (In Table 2 and all succeeding table, we have compressed the ORNL low and high case into a single mid-range estimate and adopted the CONAES high-growth variant.)

The progressive reduction in projected levels of energy consumption for a given year in the future disclosed by Table 2 is unmistakable. Studies published in 1982 typically centered on approximately 135 quads in 2020 whereas those published three years earlier averaged around 160. In other words, the projected 40-year growth rate in primary energy consumption dropped by 0.4 percent per year.[2] This scaling-back is, of course, not surprising. Successive projections to the year 2000, with which readers may be more familiar, reveal a similar scaling back: between the Bureau of Mines' projections of 1968 and EIS's of 1981, the estimated level of primary energy consumption in 2000 has been cut from around 170 to little over 100 quads. A less bullish long-term economic prognosis is one of the explanations for those steadily reduced estimates. But the demonstrated potential for, and assumed further exploitation of, energy

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[2] To be sure, studies released in a given year can frequently be based on data of quite a few years earlier so that the reining-in noted above may reflect more than a three year lapse.

Table 1. Comparative Projections of Primary Energy Consumption, GNP and Energy GNP Ratios, 1985-2050 (energy consumption in quads, GNP in trillion 1980 dollars, energy/GNP ratios in thousand Btus per dollar)

Projection	1985			1990			2000			2010		
	E	GNP	E/GNP	E	GNP	E/GNP	E	GNP	E/GNP	E	GNP	E/GNP
ETA-MACRO (Manne, 1979)*	88.04	3.01	29.25	96.67	3.50	27.62	114.98	4.48	25.66	137.79	5.52	24.96
LEAP (EIA, 1982)*	83.74	3.00	27.91	89.0	3.46	25.72	104.0	4.32	24.07	121.0	5.27	22.96
ORNL Nat. Energy Perspectives (Livingston, and coauthors, 1982)*[a]												
"Low" case	--	--	--	86.1	3.45	24.96	96.4	4.48	21.52	--	--	--
"high" case	--	--	--	90.9	3.45	26.35	116.6	4.48	26.03	--	--	--
ORAU CO_2 Study (Edmonds and Reilly, 1982)*	--	--	--	--	-	--	105.1	4.03	26.07	--	--	--
CONAES (NAS, 1979)*												
"Moderate Energy Costs"	--	--	--	--	--	--	--	--	--	93.9	3.49	26.91
"High Economic Growth	--	--	--	--	--	--	--	--	--	133.6	5.25	25.44
Fossil-2 (Kydes and Pierson, 1979)	92.0	2.96	31.08	101.0	3.48	29.02	119.0	4.57	26.04	142.0	5.83	24.36
BNL/DJA (Kydes and Pierson, 1979	104.0	3.15	33.02	112.0	3.64	30.77	117.0	4.79	24.43	130.0	6.13	21.21
RFF/SEAS (Ridker and Watson, 1980)*	93.0	2.91	31.96	--	--	--	114.2	4.49	25.43	--	--	--
DESOM (NAS,[b] 1978)	--	--	--	112.5	3.91	28.77	--	--	--	196.3	6.61	29.70
SRI (NAS, 1978)[b]	--	--	--	108.9	3.91	27.85	--	--	--	185.4	6.61	28.05
Nordhaus (NAS,[b] 1978)	--	--	--	96.1	3.91	24.58	--	--	--	129.6	6.61	19.61

Table 1. (continued)

Projection	2020			2025			2030			2050		
	E	GNP	E/GNP	E	GNP	E/GNP	E	GNP	E/GNP	E	GNP	E/GNP
ETA-MACRO (Manne, 1979)*	166.50	6.66	25.00	--	--	--	201.67	7.41	27.21	--	--	--
LEAP (EIA, 1982)*	143.0	6.43	22.24	--	--	--	166.2	7.83	21.20	--	--	--
ORNL Nat. Energy Perspectives (Livingston, and coauthors, 1982)*[a]												
"Low" case	118.7	7.43	15.98	--	--	--	--	--	--	--	--	--
"high" case	134.6	7.43	18.12	--	--	--	--	--	--	--	--	--
ORAU CO_2 Study (Edmonds and Reilly, 1982)*	--	--	--	147.32	6.49	22.70	--	--	--	197.7	9.67	20.44
CONAES (NAS, 1979)*												
"Moderate Energy Costs"	--	--	--	--	--	--	--	--	--	--	--	--
"High Economic Growth	--	--	--	--	--	--	--	--	--	--	--	--
Fossil-2 (Kydes and Pierson, 1979)	164.0	7.11	23.07	--	--	--	--	--	--	--	--	--
BNL/DJA (Kydes and Pierson, 1979	154.0	7.72	19.95	170.0	8.61	19.74	--	--	--	--	--	--
RFF/SEAS (Ridker and Watson, 1980)*	--	--	--	171.4	7.84	21.86	--	--	--	--	--	--
DESOM (NAS,[b] 1978)	--	--	--	--	--	--	--	--	--	--	--	--
SRI (NAS, 1978)[b]												
Nordhaus (NAS,[b] 1978)												

Note: The six projections denoted by an asterisk (*) are reviewed in detail in this document. For the other five, see accompanying text.

Sources: BNL/DJA, Fossil-2, DESOM, SRI, and Nordhaus from source cited in footnote on page 9; all other projected data shown in this, and subsequent tables from studies described in Appendices.

[a] These figures represent the study's projected energy demand prior to integration with supply forecasts.

[b] Growth rates for these models were assumed by NAS study in order to examine Energy/GDP relationships. They are not the authors' estimates.

Table 2. Comparative Projections of Primary Energy Consumption, GNP, and Energy/GNP Ratios, 1981 and 2020 (energy consumption in quads, GNP in trillion 1980 dollars, energy/GNP ratios in thousand BTUs per dollar)

Model	Year Prepared	Energy	GNP	Energy/GNP
Actual 1981 data	-	73.8	2.68	27.53
DESOM	1978	258	8.59	30.0
SRI	1978	240	8.59	28.0
Nordhaus	1978	151	8.59	17.6
ETA/MACRO	1979	166	6.66	25.0
CONAES	1979	160	7.06	22.7
Fossil-2	1979	164	7.11	23.1
BNL/DJA	1979	154	7.72	20.0
RFF/SEAS	1980	158	7.01	22.5
IEA/ORAU	1982	138	5.90	23.4
ORNL	1982	127	7.43	17.1
LEAP	1982	143	6.43	22.2

Note that DESOM, SRI, and Nordhaus deliberately use identical projected GNP.

Source: 1981 data from Monthly Energy Review and Economic Report of the President efficiency opportunities is an equally, if not more, important reason. Between 1973 and 1981, the energy/GNP ratio fell at an average rate of nearly 2 1/2 percent annually. So it is not unexpected that the most recent long-term-forecasts, recognizing the adjustments under way in response to rising real energy prices, assume that continued--if decelerating--declines in the energy/GNP ratio will continue under the impact of the persistent price pressures embodied in the forecasts.

Table 3, which translates the absolutes of Table 2 into average annual rates of change, points up this change of expectations succinctly. The most recent studies reviewed, taken together, suggest long-term energy growth averaging around 1.6 percent, GNP growth of approximately 2.5 percent, and an energy/GNP ratio declining by a rate of 1.1 percent. Of course, a perpetually declining energy/GNP ratio defies both economic logic and physical reality, for it suggests, on the one hand, that energy is becoming a steadily less desirable economic good, and on the other, that the nation is capable of supporting a given level of GNP by using an amount of energy approaching zero! But even at this writing, newly released studies--e.g. at Resources for the Future and the Gas Research Institute--suggest that we haven't seen the last of the observed tendency for successive analyses to scale back estimated energy consumption levels and energy/GNP ratios. Thus, in its most recent scaling back, GRI's October 1982 "Baseline" case to 2000 shows primary energy consumption of 1.4 percent yearly, reaching a level of 96.4 quads in that year (The associated GNP growth rate is 2.6 percent; the energy/GNP ratio falls by 1.9 percent). If, as suggested by Table 2, a stylized projection for the year 2020 hovers around 135 quads, to reach that level would require 1.7 percent growth rate from the GRI 2000 level. As noted above, energy growth, significantly trailing GNP growth in perpetuity doesn't seem in the cards, so that the possibility of some eventual step-up in the energy growth rate cannot be dismissed. But it is hard to imagine such a turning point less than two decades away. What this suggests is that 135 quads is very likely near to an upper limit to the level of demand in 2020, while a mid-range spread of, say, 115-125 quads appears to be a much more reasonable extension of the most recent thinking by GRI and others.

Table 3. Comparative Projected Average Annual Percentage Change in Primary Energy Consumption, GNP, and Energy/GNP Ratio, 1981-2020

Model	Year Prepared	Energy	GNP	Energy/GNP
DESCOM	1978	3.3	3.0	0.2
SRI	1978	3.1	3.0	0.0
Nordhaus	1978	1.9	3.0	-1.1
ETA/MACRO	1979	2.2	2.4	-0.2
CONAES	1979	2.0	2.5	-0.5
Fossil-2	1979	2.1	2.5	-0.4
BNL/DJA	1979	1.9	2.7	-0.8
RFF/SEAS	1980	2.0	2.5	-0.5
IEA/ORAU	1982	1.6	2.0	-0.4
DRNL	1982	1.4	2.6	-1.2
Leap	1982	1.7	2.3	-0.6

Note: All rates of change are calculated using the authors' absolute levels for 2020 (or our estimates thereof) and actual figures for 1981. Thus, the rates of change shown may differ from rates shown in the different models, based on other base years.

Consumption of Specific Energy Sources and Forms

Table 4 compares the projected distribution, by source, of primary energy consumption in six of the models reviewed. The one respect in which all studies concur is the disproportionally large expansion forseen for nuclear power. Not surprisingly, EIA's LEAP results, released in early 1982, reflect the least expansive nuclear outlook (corresponding to 285 GW of installed capacity in 2020 compared to 55 GW in 1981) and even this projection embodies optimistic assumptions regarding a resurgent nuclear momentum. It is questionable whether the earlier studies surveyed would continue to stick with their high nuclear projection. Coal is also projected, in most studies, to raise its absolute and relative standing. (Primary coal use includes that component of the resource dedicated to synthetic fuels.) The natural gas share declines significantly in all studies. Oil declines less sharply--in part due to expectations regarding growth of an oil shale industry. Somewhat unexpectedly, solar and other "frontier" technologies do not loom large in most of the studies. There may be two reasons for this curiosity: (1) Definitional - displaced fuel and power use due to passive solar may be treated as conservation rather than as a solar contribution. (2) Methodological and informational - models may be so driven (with respect to demand, relative price, commercialization, penetration rates, etc.) as to make it difficult to incorporate systems for which there are no historical data and relationships. Only in the ETA/MACRO model is there an allowance for a catchall "backstop" technology component. (Backstop describes an inexaustible but high-cost energy resource, including low-temperature solar heating, biomass conversion, and--it should be noted--certain unconventional hydrocarbons, which other models may intermingle with oil and gas.)

A different and, in some ways, more sharply focused way of looking at future changes in energy-demand patterns is to consider consumption at the delivered (or end use or net energy) stage. Two studies may substantially agree on expected levels of delivered energy only to differ markedly on the corresponding levels of primary consumption since they reflect different

Table 4. Comparative Distributions of Primary Energy Consumption (percents)

	Actual 1981	CONAES 2010	ETA/ MACRO	LEAP	ORNL	IEA/ ORAU	RFF SEAS
			2020			2025	
Coal	22	13	32	50	38	24	21
Oil	43	42	) 18	14	23	35	37
Natural gas	27	12	)	10	17	14	11
Nuclear	4	) 33	24	13	20	21	24
Hydro, geothermal	4	)	6	) 13	1	4	4
Other	a)	-	20	)	1	2	4
Total	100	100	100	100	100	100	100
Total, in quads	74	134	166	143	127	147	171

Source: 1981 data from Monthly Energy Review

a) Recent EIA data suggest that renewable energy sources (principally wood) represent about 2 quads or 3 percent of an augmented total. That estimate is not included in the table.

judgments about, say, the proportion of primary enery committed to synfuel or electricity production and the attendant conversion losses[3]. However, as Table 5 indicates, significant model variability occurs when looking both at primary and end-use demand levels.

The table shows that primary energy growth is expected to exceed delivered energy growth by an average of around 0.4 percentage points. (Between 1960 and 1981, primary energy rose by 2.5 percent yearly; delivered energy, by 1.9 percent.) Only in the RFF/SEAS model is there a negligible gap between the two projected indicators; this is explained by that study's exceedingly optimistic assumptions about prospects for significantly enhanced electric conversion efficiency.

The principal reason for faster growth of primary, as against delivered, energy is the steadily rising importance of electric power, capable of being fueled by abundant coal and nuclear resources. (Each model looks to coal and nuclear as providing virtually the entire incremental source of future generating capacity.)

In Table 6, we decompose delivered energy growth as between its electric and non-electrical form. In 1979, electricity represented around 11 percent of delivered energy in the United States. If, say, the LEAP projection shown in Table 6 represented the most plausible course of development over the next four decades, it would raise that share to nearly 20 percent. (The share of primary energy dedicated to electricity would, correspondingly, rise from 27 percent to around 40 percent.)

As noted earlier, both electricity and synfuel conversion account for disparate trends between primary and delivered energy. To get an impression of how the studies surveyed view the emerging role of synfuels vis-a-

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[3] It needs to be noted that the statistical tradition which, for historical data, limited the difference between primary and net energy to electric conversion losses and which, for projections, adds in synfuel conversion losses, is somewhat quixotic. Other energy conversion facilities experience losses (and some gains) in the process of delivering energy to final users.

Table 5. Comparative Projected Trends in Primary and Delivered Energy (average annual percentage rates of change)

Model	Period	Primary	Delivered
ETA/MACRO	1985-2030	1.9	1.5
LEAP	1980-2030	1.5	1.0
ORNL	1979-2020	1.2	0.7
ORAU/IEA	1975-2025	1.4	1.0
CONAES	1975-2010	1.8	1.5
RFF/SEAS	1975-2025	1.7	1.6

Table 6. Comparative Projected Average Annual Rates of Percent Change in Electricity, Non-Electric Delivered Energy, and Total Delivered Energy

Model	From 1979 to year shown	Electricity	Non-electric energy	Total delivered energy
CONAES	2010	2.0	1.0	1.1
ETA/MACRO	2020	3.2	1.0	1.4
LEAP	2020	2.2	0.6	0.8
ORNL	2020	2.9	0.1	0.6
IEA/ORAU	2025	3.4	0.3	0.7
RFF/SEAS	2025	3.0	1.4	1.6

vis conventionally processed and more traditional energy forms[4], we turn next to a table which shows the projected levels of delivered energy in terms of that distribution. Panel (a) of Table 7 presents projected absolute data, Panel (b) presents the percentage distribution of those data, and Panel (c) provides a percentage distribution of incremental changes between 1979 and the target date of the projection. This last part of the table expresses the prospective changes foreseen in the different studies tellingly. It enables us to track the proportionate importance of different energy forms in changes in the level of delivered energy over the next 30-40 years. As noted already, electricity is a major component of that projected increase. Liquids and gases derived from conventional and unconventional sources tend not only not to contribute to increased overall delivered energy demand (as the domestic reserve situation for those fuels continues to worsen and imports are, for policy or other reasons, assumed to be limited) but, in fact, represent the offsets to those components that do loom large in the total increment. These are, in addition to electricity, liquids and gases based on synthetic processes and coal in direct application. Although synfuels figure significantly in all the models compared, there is great variability in the range of estimates--a phenomenon which no doubt reflects the large unknowns that still surround the economic and technological characteristics of these complex undertakings. This statement applies even more to comparative projected estimates of the diversity of energy systems subsumed under the "backstop" item. There is no persuasive evidence that this category was accorded thoughtful attention--particularly in those models actually showing a lesser contribution 40-45 years hence than today.

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[4] Unless otherwise specified, "unconventional" sources of oil and gas are included in what are in the text termed "conventionally processed" energy forms.

Table 7. Comparative Projections of Delivered Energy, By Form

	Actual 1979[c]	CONAES 2010	ETA/ MACRO	LEAP	ORNL	IEA/ ORAU	RFF/ SEAS
			2020			2025	
	(a) in quads						
Electricity	7.1	13.1	25.9	17.3	22.8	23.6	27.6
Oil	33.8	44.8	NA	30.7	27.4	46.9	69.3
Gas	16.9	14.4	NA	14.3	19.4	12.2	19.1
Oil and Gas	50.7	59.2	38.7	45.0	46.8	59.1	88.4
Synfuel[a]	-	20.0	17.8	32.3[d]	30.0	25.0	29.3
Other	50.7	39.2	20.9	12.7	16.8	34.1	59.1
Coal	3.9	17.7	14.0	14.9	10.1	5.8	9.9
"Backstop"[b]	1.8	-	32.7	11.3	1.4	-	6.4
TOTAL	63.5	90.0	111.3	88.6	81.1	88.4	132.3
	(b) Percent distribution						
Electricity	11.2	14.6	23.3	19.5	28.1	26.7	20.9
Oil	53.2	49.8	NA	34.7	33.8	53.1	52.4
Gas	26.6	16.0	NA	16.1	23.9	13.8	14.4
Oil and Gas	79.8	65.8	34.8	50.8	57.7	66.9	66.8
Synfuel	-	22.2	16.0	36.5	37.0	28.3	22.1
Other	79.8	43.6	18.8	14.3	20.7	38.6	44.7
Coal	6.1	19.7	12.6	16.8	12.5	6.6	7.5
"Backstop"	2.8	-	29.4	12.8	1.7	-	4.8
TOTAL	100.0	100.0	100.0	100.0	100.0	100.0	100.0
	(c) Percent distribution of increment from 1979						
Electricity	-	22.6	39.3	40.6	89.2	66.3	29.8
Oil	-	41.5	NA	-12.4	-36.4	52.6	51.6
Gas	-	-9.4	NA	-10.4	14.2	-18.9	3.2
Oil and Gas	-	32.1	-25.1	-22.7	-22.2	33.7	54.8
Synfuel	-	75.5	37.2	128.7	170.5	100.4	42.6
Other	-	-43.4	-62.3	-151.4	-192.7	-66.7	12.2
Coal	-	52.1	21.1	43.8	35.2	7.6	8.7
"Backstop"	-	-6.8	64.6	37.8	-2.3	-7.2	6.7
TOTAL	-	100.0	100.0	100.0	100.0	100.0	100.0

Footnotes to Table 7

[a] Assumed to comprise largely shale- and coal-derived liquids and gases. For some models the estimates shown do not appear in the appendices to this report but were circuitously derived from indications in the original document containing the model results. To the extent that there is coal-produced low-BTU syngas for electric generation, that would presumably not be reflected in this row but in the electricity row.

[b] This is the ETA/MACRO term for a host of renewable and other frontier technologies. Clearly, this item is treated cavalierly by those models showing little or no component 40 years hence.

[c] We have added an estimated 1.8 quads in renewables to the published Monthly Energy Review figure on delivered energy.

[d] Including unconventional sources of gas.

Sectoral Trends

Table 8--again subdivided into three panels as in the preceeding tabulation--decomposes projected levels of delivered energy demand into principal using sectors. In this comparison, we are unable to include the ETA/MACRO model which lacked the necessary breakdown. And we chose to omit the IEA/ORAU study for it produced a set of results which the authors recognized as pointing to possible shortcomings in the existing version of the model. The clearcut trend revealed by Table 7 is the disproportionately great importance in future years of the industrial sector in contrast to the falling relative importance of transportation, households and the commercial sector. It appears--perhaps not unreasonably--that industrial energy demand will much more closely track overall economic growth than will other activities. It is also possible, however, that the many disparate energy-using processes in industry are less susceptible to analysis of conservation potentials than such uses as the automobile and the heating of buildings. It is therefore an open question whether the more dimly perceived efficiency improvements in industry bias that sector's future energy demands somewhat on the high side.

Pre- and Post-2000 Economic and Energy Consumption Trends

It is useful, finally, to note contrasts, if any, in the pre- and post-2000 energy and economic trends disclosed by the models. We are able to do this for four of the studies reviewed, as shown in Table 9. (In order to avoid the distorting effect of different and unrepresentative base years, we measure the pre-2000 trend from 1985 or 1990.) Needless to say, the year 2000 is an arbitrary benchmark which may lie on a longer-term, smoothly changing pattern of development rather than representing a sharp point of discontinuity.

Table 8. Comparative Projections of Delivered Energy, By Using Sector

	Actual	CONAES	LEAP	ORNL	RFF/SEAS
	1979[a]	2010	2020	2025	
(a) In quads					
Residential	11.9	NA	12.0	NA	11.6
Commercial	7.4	NA	7.7	NA	15.5
Res. & Comm.	19.3	16.9	19.6	21.8	27.1
Industry	24.2	45.7	49.8	37.2	67.7
Transportation	20.0	27.4	19.2	22.1	37.5
TOTAL	63.5	90.0	88.6	81.1	132.3
(b) Percent distribution					
Residential	19	NA	14	NA	9
Commercial	12	NA	9	NA	12
Res. & Comm.	30	19	22	27	20
Industry	38	51	56	46	51
Transportation	31	30	22	27	28
TOTAL	100	100	100	100	100
(c) Percent distribution of increment from 1979					
Residential	-	-	0	-	0
Commercial	-	-	1	-	12
Res. & Comm.	-	-9	1	14	12
Industry	-	81	102	74	63
Transportation	-	28	-3	12	25
TOTAL	-	100	100	100	100

[a] Monthly Energy Review data except split beween Residential and Commercial is estimated on basis of other EIA information.

Table 9. Pre- and Post-2000 Energy and Economic Trends
(average annual percentage rates of change)

	Pre-2000			Post-2000		
	Energy	GNP	E/GNP	Energy	GNP	E/GNP
ETA/MACRO[a]	1.8	2.7	-0.9	1.9	1.7	0.2
LEAP[a]	1.5	2.5	-1.0	1.6	2.0	-0.4
ORNL[b]	1.9	2.6	-0.8	0.9	2.6	-1.6
RFF/SEAS[c]	1.4	2.9	-1.5	1.6	2.3	-0.6

[a] The periods being compared are 1985-2000 and 2000-2030

[b] 1990-2000 and 2000-2020

[c] 1985-2000 and 2000-2025

Three of the four projections concur in their overall thrust:

- Real GNP growth declines markedly between the two intervals
- Energy/GNP ratios experience a distinct slowdown in their rate of decline
- Growth of energy consumption shows little basic change

The GNP slowdown is consistent with declining population and productivity growth (the latter presumably associated in part with a prospectively changing economic mix away from manufacturing). The lower rate of decline in nationwide energy intensity may reflect judgments both about diminishing technological opportunities for energy conservation and about less upward pressure on energy prices as domestic backstop technologies attenuate the link, and force an asymptotic limit, to a rising world oil price. Thus, the LEAP model is governed by a world oil price trajectory rising at around 4 percent per year during 1980-2000 and at approximately one percent thereafter.

A Note on the STANFORD/IES Model

As mentioned at the outset, the Stanford study was not susceptible to being easily compared with the other models in a quantitative fashion. The study sought to define two sets of value systems--one described as having a "hard energy" orientation, the other as "soft energy." Each of those two--rather idealized--types of orientations was characterized by 10 qualitative factors ("dominant social paradigms"). For example, hard energy presumed an inclination toward competition and achievement, soft energy towards cooperation; hard energy presumed unbounded material progress, soft energy bounded material progress; and so on. Three projection scenarios were constructed whose quantitative results depended on the proportion of the population subscribing to one or the other value system. Thus, in the year 2025, the hard energy group was taken to represent 95 percent of the population in scenario I, half the population in scenario II, and 10 percent in scenario III.

In a fashion that is not entirely clear, the value specifications were combined with the Brookhaven Energy System Optimization Model (BESOM) in order to generate a set of quantitative results. These produced primary energy demands in the year 2025 of--

100 quads in scenario I
80 quads in scenario II
48 quads in scenario III

The Stanford effort represents a start in developing an analytical framework for interrelating subjective and social factors, on the one hand, with quantitative economic and energy variables, on the other. Clearly there are both methodological and semantic problems--for example, whether the third scenario is capable of generating the minimum level of real income sufficient to justify characterizing such a scenario as accommodating acceptable group welfare goals.

CRITICAL OBSERVATIONS

The foregoing review of energy projections beyond the year 2000 has focused primarily on cross-model comparisons of numerical findings. It remains to touch briefly, and very generally, on a few of the critical analytical and methodological issued disclosed by these as well as other long-range energy projections.

(1) The "Datedness" Issue. It is clear that, with very brief passage of time, projections 40 years hence have changed in a major way. To the extent most study results are heavily price-deterministic, the fact that oil-price escalation during just 1979-80 equalled what a number of studies had assumed would occur over the course of three decades (i.e., a 2-3 percent annual rise in real oil prices) reasonably explains the scaling-back reflected in the most recent forecasts. With ongoing energy-market developments so changeable, one wonders about the utility of large-scale

sophisticated models unless they can be continuously cranked up to embody, and generate the quantitative implications of, such changing trends.

(2) Differences in the Character of the Models. The studies reviewed in this report varied in their scope and methodology. For example, ETA-MACRO was an equilibrium model explicitly designed to show how energy markets respond to changing prices, levels of demand, and quantities supplied. by contrast, the ORNL study was cast within a normative, goals-oriented framework with a simple analytical approach largely dependent on energy's relationship to future growth of the economy. It is clear, therefore, that changes in projected energy levels from one of the earlier to one of the later models can reflect not merely the influence of real-world developments but differences in the properties of the models.

(3) The Technology Element. "Optimization Modelers" are most comfortable when they can specify all critical inputs and relationships in unambiguous quantitative forms. Thus, penetration of synfuels and--more broadly--of "backstop technologies" tends to be treated in too disembodied a fashion, in which their appearance is tightly governed by relative supply prices and other variables and parameters. Yet, observing the chronically roller-coaster behavior of synfuel projects, one wonders whether such technological components of a future energy system might not be treated more effectively "outside," or as an adjunct to, a formal model. Relatedly, even sticking by our recognition--stated at the outset of this discussion--of the long-range planner's need to know, it is hard to know what to make of models which, given the present state of total uncertainty, nonetheless project 21 quads of primary energy from breeders and fusion in 2025.

(4) Plausible vs. Counter-Intuitive Results. It is not always clear whether the plausible results of one model vs. the counter-intuitive results of another reflect the contrasting characteristics and assumptions of the two efforts or the fact that the plausible results represent massaging designed to mute a previous set of perverse outcomes. By "massaging," we do not refer to unprofessional behavior. The fact is,

however, that few respectable forecasting efforts fail to allow themselves a pass at making at least some "judgmental adjustments" when a set of findings so dictate.

(5) The Role of Renewables. In contrast to the robust place accorded to synthetics, in most of the studies reviewed, solar and renewables are treated erratically and, one suspects, somewhat slighted. It is not clear whether that defect arises from the lack of energy accounting conventions or from lack of information and confidence (certainly, that did not inhibit quantitative conjecture about other technologies). Development of an expanded system of energy accounts that permits embodying solar and renewable sources would be helpful.

As in all cased involving the use of long-term projections, readers must be reminded that, no matter how cavalier our occasional use of words, the findings reported here are not predictions but rather a set of outcomes conditioned by assumptions about changes in policy and economic variables, dependent on the accuracy of a host of technical parameters, and governed, in general, by a great deal of uncertainty regarding technological processes and structural change. Just a few examples will indicate the kinds of unknowns with which we must contend. Knowledge about the effects of rising energy prices, which virtually all long-range analysis assume, are severely handicapped by inadequate historical experience and the resultant absence of a suitable data base. Under circumstances where energy markets have been considerably constrained by public regulation, the future effects of deregulation are hard to pin down. Fifty-year forecasts of industrial input-output coefficients, heavily relied upon in the RFF/SEAS model, represent a fragile, if ultimately still useful, forecasting tool. A general equilibrium approach (such as the ETA/MACRO model), requiring for its solution mutually interactive adjustments on the demand and supply sides has conceptual elegance but is heroic in the many variables and relationships that must be quantified whether or not there is compelling empirical justification. The more modest sectoral end-use models, by contrast, provide considerable insight into particular energy consumption trends while leaving open overall adjustment processes.

The recognition that there is much about the demographic, economic and energy profile of the 1980's that could not easily have been anticipated in the 1930s and 1940s ought to give us pause about the robustness of projections 40-50 years hence. Today's developments in computers, communications, and even the pervasive consequences of automotive growth could not be credibly assumed 40-50 years ago, let alone spun out in their quantitative implications. As late as 1947, Census Bureau demographers--reeling from what they perceived to be a chronic continuation of the low depression birth rate--projected a year 2000 population of 164 million, a level reached in 1955!

All these caveats aside, projections for the first quarter of the next century are, as we noted at the outset of this discussion, increasingly demanded. Some comfort can be derived from the reasonable degree of concensus surrounding numerous indicators which were projected in the different studies reviewed. At the same time, both producers and users of long-term projections have a responsibility for continual monitoring of such new data, new analytical tools and significant departures in demographic, economic and energy developments as to compel a re-assessment of the long-range trends previously charted. In this respect, the ability to differentiate fundamental, as distinct from ephemeral, change in conditions is no small part of the task that must be faced up to.

PART TWO: APPENDICES

Appendix A

Summary of ETA-MACRO

I. Background

ETA-MACRO is an integrated model of energy-economy relations developed by Alan Manne of Stanford University. It represents a merger of a process analysis model for Energy Technology Assessment (ETA) with a macroeconomic growth model (MACRO) that accounts for substitution possibilities between capital, labor, and energy inputs. ETA-MACRO is designed to compare the options that are available to the United States as the country moves away from its present heavy dependence on oil and gas resources toward a more diversified future energy economy (U.S. DOE, 1979b). Manne (1977) has considered the impact of a nationwide moratorium on nuclear reactor construction. Schmitt and coauthors (1977) have used ETA-MACRO to study how future technology and fuel mixes will be affected by higher cost prices, economic and regulatory constraints on coal production, oil import ceilings, the timing and costs of new technologies such as fast-breeder reactors, and other variables. Hamilton and Manne (1977) have, in cooperation with Brookhaven National Laboratory, analyzed the health and environmental costs of alternative energy production and consumption patterns using the model.

II. Methodology

ETA-MACRO was built with the long-run picture in mind. It has a eighty year time horizon extending to 2050, within which there are sixteen discrete five-year planning periods. It is assumed that producers and consumers will be sufficiently far-sighted to anticipate future scarcities and rising energy prices. The approach taken by Manne allows explicitly for (Manne, 1978):

1. Energy-economy interactions--the prospect that rising energy costs and limited supplies will prevent the economy from achieving its full potential GNP growth rate, and that this in turn will slow down future capital accumulation.

2. Cost-effective conservation--rising prices will operate through demand elasticities to reduce energy demands below the levels projected from historical trends.
3. Interfuel substitution--changing conditions will induce consumers to replace oil and gas with electricity.
4. New supply technologies--synfuels, nuclear, and solar power, each with its own difficulties and uncertainties on costs and dates of introduction.

The ETA component of the model is used to approximate a market equilibrium for its energy sector by solving a dynamic non-linear programming problem. Energy demands are aggregated into two broad categories of secondary energy forms, electric and nonelectric. Estimates of the demand for energy are determined through a hybrid of econometric and engineering process techniques. The energy demand functions provide for substitutability between energy and other economic inputs, and the ease or difficulty of such tradeoffs is summarized through the cross-elasticity parameter. The allocation of demand between the two forms of energy (market share) is found using individual price elasticities (U.S. DOE, 1979b). Given this demand for electric and non-electric energy products, a conventional linear programming analysis which equates factor shadow prices (marginal values) to the long-run costs of supply is used to meet the demand at least cost.

The following supply technologies are included in ETA (Manne, 1977):

1. Electric
   a. hydro, geothermal, wind, etc.*
   b. remaining initial fossil electric*
   c. coal-fired electric, low cost regions
   d. coal-fired electric, high cost regions
   e. light water reactors, no plutonium recycle
   f. light water reactors, with plutonium recycle
   g. liquid metal fast breeder reactor
   h. advanced solar electric or fusion
2. Non-Electric
   a. petroleum and natural gas
   b. coal-based synfuels (liquids and gases)
   c. shale oil

d. electrolytic hydrogen

e. two "backstop" non-electric alternative energy systems, equivalent to oil and gas at $5/million BTU or $8/million (1978 dollars) Btu[1]

f. coal - direct uses other than electricity generation and synfuels*

*Exogenously determined activity levels.

For each supply source a price quantity schedule is constructed indicating capital and associated costs involved in the extraction, generation, and conversion of the final form of energy at various dates in the future (U.S. DOE, 1979b). Little emphasis is given to energy transmission and regional cost differentials, except in the case of coal-fired electricity generation (U.S. DOE, 1979a). In addition to the costs of various technologies there are other constraints that can be imposed. These include constraints on the growth of capacity for any technology, limits on oil imports, restrictions on the rate of introduction of new technologies, and bounds on the extent of domestic resource extraction. Alternative scenarios can be generated to examine the implications for energy prices and economic growth by making different assumptions about costs, dates of availability or rates of increase in capacity for the various technologies. In Manne (1977), cost parameters are taken from the Committee on Nuclear and Alternative Energy Systems (CONAES) Modeling Research Group. Two other sets of cost parameters are reported in Manne (1976) and Schmitt and coauthors (1977).

In order to focus upon the long-run issues of energy-economy interactions (resource exhaustion and the introduction of new technologies), the economy is described in highly aggregated terms. All economic quantities outside the energy sector are combined on a value basis and allocated to "consumption," "investment," or "energy costs." An intertemporal market equilibrium for the energy sector is approximated by optimizing for the minimum of the sum of conservation, interfuel substitution, and energy supply costs. The objective function, which is non-linear, treats the costs and benefits in present dollars by using a 75-year planning horizon and a social discount rate. Except for the use of the higher discount rate, which reflects uncertainty about the future, the optimization is in a deterministic framework.

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[1] The term "backstop" is used to describe an inexhaustible but high-cost energy resource. Examples cited by Manne include low-temperature solar heating, biomass conversion, and unconventional hydrocarbons.

Trends in the labor force-productivity growth index provide the principal driving force for the potential GNP and, hence, the expansion of energy demands over time. Demand growth in the two sectors, electric and non-electric, is expressed as a function of the annual rate of GNP growth, own and cross-price elasticities (exogenously determined), and the annual rates of own-price increase and competing, fuel price increase (endogenously determined). A unitary elasticity of substitution for electric and non-electric energy demand is assumed; however, the equilibrium electric energy demand has an upper bound, expressed as a fixed value share of total primary energy.

III. Assumptions and Conventions

Applications of the ETA-MACRO Framework require the following information:

1. Macroeconomic variables--the potential GNP growth rate at constant energy prices, elasticity of aggregate energy demand substitution, and "value shares" for the nested production function.
2. Upper bounds (if any) to represent environmental restrictions on total coal consumption.
3. Cumulative supply curves--quantity made available versus marginal selling price (replacement cost) for oil and gas.
4. Introduction limits (if any) and input-output coefficients for each supply technology.

Output data consists of: domestic energy consumption (by source), cumulative resource requirements, nuclear fuel requirements, energy prices, GNP, present value of consumption at a 5 percent and 10 percent discount rate, annual investment rates for electric utilities, and production capacity levels for all technologies.

A number of alternative projections have been made using the ETA-MACRO framework, several of which were cited earlier in this discussion. Manne (1979) is particularly instructive because it goes into detail on the variations in model output resulting from different initial assumptions. Manne varies the percentage annual OPEC price increase, the elasticity of demand substitution (ESUB), and nuclear reactor capacity ceilings to develop four alternative scenarios.

Table 1. Specification of the Four ETA-MACRO Scenarios

	1	2	3	4
% OPEC Price Increase	4%	2%	4%	4%
ESUB	.30	.30	.50	.30
Nuclear Capacity	250	250	250	0

Underlying each of the four scenarios are a series of common assumptions about GNP growth, imports, domestic fossil supplies, and electricity supply. These assumptions include:

1. Energy demand:

   A. Potential GNP growth will be 3.4 percent between 1978 and 2010; and 2.0 percent after 2010. (Potential GNP growth represents expected growth with no changes in energy prices, the realized growth rate as calculated by the model is somewhat lower.)

   B. Price controls to be modified gradually so that domestic consumers pay incremental replacement costs of energy.

2. Oil and gas imports:

   A. United States to limit crude oil, petroleum products, and LNG imports to 8.5 mb/d ≈ 17 quads/year. (Note: 1.0 mb/d ≈ 2 quads/year ≈ 50 million tons oil equivalent/year.)

3. Domestic fossil fuel supplies call cost figures in 1978 dollars:

   A. Remaining conventional domestic oil and gas resources recoverable at prices of $2-$5/mBtu: 1,600 quads. Equivalent to 40 years at 1975 production rate.

   B. Coal consumption limited to 40 quads in 2000, approaching a 60 quad asymptote (versus 13 quads in 1975). 60 quads is approximately 2.70 billion tons of coal.

   C. Costs and rates of introduction of synthetic fuels and backstops:

	Cost ($/mBtu) 1978 Dollars	Quantities of crude oil equivalent available in year 2000	
Shale oil	$4.5	2.0 quads	1.0 mb/d
Coal-based synthetics	5.0	3.0	1.5
Backstops	8.0	3.0	1.5

4. Electricity supplies:

   A. Light water nuclear reactors (LWR) limited to 250 gigawatts (GW) in 2000 (versus 30 GW in 1975). Once-through fuel cycle. 6.0 million short tons uranium oxide available at prices up to $100/pound (domestic + imports).

   B. Post-2000 nuclear power limited to base-load service.

   C. Total contribution from hydroelectric, geothermal, solar, etc. limited to 2.5 percent/year growth from 1975 level.

   D. Advanced electric technologies (breeder fission, fusion, or solar) limited to 6 GW by 2020. Initial investment cost: $1300/kW (versus $900 for LWR).

IV. ETA-MACRO Projections

Projections from the base case and one variation of it are discussed below. The quantities reported are supply/demand balances, allowing breakdowns by fuel for both production and consumption to be readily made. However, due to the model's reliance on a heavily aggregated production function to represent economic growth it is not possible to get a breakdown by consuming sectors such as transportation, industrial, and so on. Table

2 outlines the projected primary energy balances through 2030 corresponding to the base case projections.

Table 2. ETA-MACRO Base Case Primary Energy Balances
(quads)

	1985	1990	2000	2010	2020	2030
Coal	21.41	27.28	37.83	47.70	52.90	56.10
Electricity generation	15.36	19.52	23.91	27.29	25.82	25.57
Synthetic fuels	0.0	0.75	4.50	8.92	13.08	13.46
Direct use and other	6.05	7.01	9.42	11.49	14.00	17.07
Petroleum and gas	42.00	42.00	34.50	26.92	20.82	16.07
Nuclear (light water reactors)	5.12	6.83	14.24	25.25	40.85	56.58
Shale oil, tar sands, etc.	0.0	0.50	2.00	6.00	10.00	12.00
Backstop Nonelectric	0.0	0.50	3.00	9.95	32.66	49.06
Hydroelectric, geothermal, etc.	3.90	4.42	5.65	7.24	9.27	11.86
Total domestic production	72.43	81.53	97.22	123.06	166.50	201.67
Petroleum and gas imports	15.61	15.14	17.76	14.73	0.0	0.0
Total energy consumption (= total supply)	88.04	96.67	114.98	137.79	166.50	201.67
Net energy delivered	69.00	73.90	83.50	94.60	111.00	134.00

Note: Net energy calculated using Manne's implicit 0.34 conversion efficiency for electricity generation and assuming 0.6 for coal-based synthetic fuels.

Source: Manne (1979).

The same quantities in percentage terms make it easier to see the trends underlying these primary energy balance projections.

Given the 4 percent annual increase in OPEC prices postulated for this scenario and the assumed costs for the "backstop" technology, the backstop becomes competitive with oil just after 2000 and penetrates the market quickly from then on. Coal has its highest market share in 2010, declining at a modest rate through 2030, during which time nuclear power picks up the slack in base-load electrical generation capacity. Petroleum and gas decline steadily throughout the forecast period, particularly as the backstop technology becomes relatively more attractive after the turn of the century. Synthetics also become an important source at this time, growing sharply until 2020 and then essentially leveling off. The hydroelectric and geothermal category represents a growing, but limited proportion of total energy through 2030. After 2010, petroleum and gas imports drop off rapidly, ceasing entirely by 2020.

Table 3. Base Case Composition of Primary Energy Balances Over Time (percent)

Fuel	1985	1990	2000	2010	2020	2030
Coal	24	28	33	35	32	28
Petroleum and gas	48	43	30	20	13	8
Nuclear	6	7	12	18	25	28
Shale oil, etc.	0.0	0.5	2	4	6	6
Hydro and geothermal	4	5	5	5	6	6
"Backstop" nonelectric	0.0	0.5	3	7	20	24
Petroleum & gas imports	18	17	15	11	0.0	0.0
	100	100	100	100	100	100

Note: Totals may not add due to rounding.

There are also substantial shifts in the composition of sources for electricity generation. The data in table 4 indicate that there is a virtual "flip-flop" in the relative contributions of fossil and nuclear generation, while the hydroelectric and geothermal category basically holds its own.

An interesting variation of the base case is the "flexibility" or conservation case. This is the same as the base case except that the

Table 4. Base Case Composition of Electricity Generation Over Time (percent) and Total Generation (quads)

Fuel	1985	1990	2000	2010	2020	2030
Hydro and geothermal	13.6	13.0	12.6	12.1	12.2	12.6
Fossil electric	68.6	66.9	55.7	45.7	34.1	27.2
Nuclear	17.8	20.1	31.7	42.2	53.7	60.2
	100	100	100	100	100	100
Total generation	9.8	11.6	15.3	20.4	25.9	32.1

economy's ability to replace energy inputs with non-energy inputs, as measured by the elasticity of substitution (ESUB) parameter in the model's aggregate production function, is considered to be somewhat greater. The ESUB parameter is 0.50 in this case (indicating that a 1 percent increase in energy prices will lead to a 0.5 percent decrease in energy demand), as compared to 0.30 in the base case. The projections of primary energy balances for this case are summarized in table 5.

Table 5. ETA-MACRO Conservation Case Primary Energy Balances (quads)

Fuel	1985	1990	2000	2010	2020	2030
Coal	19.72	23.80	33.76	47.70	52.90	56.10
Electricity generation	13.67	16.04	19.84	21.47	21.00	20.48
Synthetic fuels	0.0	0.75	4.50	14.74	17.90	18.55
Direct use and other	6.05	7.01	9.42	11.49	14.00	17.07
Petroleum and gas	42.00	42.00	34.50	26.92	20.82	16.07
Nuclear (light water reactors)	5.12	6.83	14.24	22.20	31.30	43.58
Shale oil, tar sands, etc.	0.0	0.50	2.00	6.00	10.00	12.00
Hydroelectric, geothermal, etc.	3.90	4.42	5.65	7.24	9.27	11.86
"Backstop" non-electric	0.0	0.50	3.00	7.52	12.19	22.23
Total domestic production	70.74	78.05	93.15	117.59	136.47	161.84
Petroleum and gas imports	12.96	9.83	6.98	0.0	0.0	0.0
Total energy consumption (= total supply)	83.69	87.88	100.13	117.59	136.47	161.84

Total energy consumption in this case is, by 2030, nearly 40 quads less than in the base case, while GNP is about $280 billion greater than in the base case. Table 6 makes similar comparisons for each of the benchmark years over the projection period. In all years, it holds that reduced energy consumption is associated with increased GNP, evidence that energy conservation does not have to be "bought" with lower economic growth.

Table 6. Total Energy Consumption and GNP Projections--"Base Case" and "Flexibility Case"
(1978 dollars)

	1965	1990	2000	2010	2020	2030
Base Case						
Energy Consumption	88.04	96.67	114.98	137.79	166.50	201.67
GNP	2.539	2.946	3.771	4.651	5.611	6.238
Flexibility Case						
Energy Consumption	83.69	87.88	100.13	117.59	136.47	161.84
GNP	2.556	2.981	3.678	4.876	5.844	6.524

Source: Manne (1979).

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Appendix B

Summary of Energy Information Administration Long-term Projections

I. Background

The post-2000 projections published by the U.S. Energy Information Administration in its 1981 Report to Congress are based on results of the Long-term Energy Analysis Program (LEAP) model, a highly detailed dynamic model of energy supply, conversion, and demand in the United States. These projections focus on energy consumption, supply, and prices and their relationship to world oil prices, improvements in technology, geologic constraints, economic growth, and regulatory policy. The framework used considers only those factors thought to represent the major forces that influence energy markets and for which a reasonable estimate of future outcomes can be made, so there is no attention given to, say, the implications of a supply disruption. Rather an attempt is made to learn more about how the choices made by energy suppliers and consumers interact to determine levels of production, consumption, and prices for various types of energy. Projections for 2000 to 2030 pay particular attention to new technologies and the use of renewable resources, both of which are expected to penetrate the market in a significant way after 2000.

II. Methodology

The model uses a "generalized equilibrium" approach to represent the supply/demand situation over time and covers all major fuels from primary resources to end use energy consumption. The key feature of this approach is that it allows the complex decision problems represented by the model to be broken down into manageable parts, while preserving the links between each part. A "network" structure containing various energy efficiencies, resource availabilities at different prices, and capacity constraints associated with certain energy technologies is the basis of the LEAP framework. This network describes interactions among the various processes that are considered to form the energy system, including supply, demand, conversion, allocation, and transportation. Demand is projected using a simplified growth model to determine sector activity and the price elasticity of demand for end use energy in each sector, together with information on prices and demand in the preceding period. Four end use sectors: (residential, industrial, commercial, and transportation) are accounted for in the analysis.

Oil, natural gas, coal, and uranium are the corresponding supply activities, with the production of these primary resources disaggregated into appropriate supply regions. Sectors for electric utilities, energy conservation, and energy distribution are used to connect supply and demand. Demand is distributed among competing sources of supply via a set of allocation processes and the market share captured by each technology is treated basically as a function of the price of energy product produced by each technology. A lag term is also included to relate market shares in each period to those in the preceding period.

Given this framework, projections are generated by finding, for each time period under consideration, the set of prices and quantities that satisfies the physical and behavioral relations embodied in the processes and linkages defined by the network. The model, unlike most, does not "optimize" with respect to a single explicit planning objective, but rather operates through decentralized decision-making so that the optimizing behavior can occur within each activity. The model then solves for the market equilibrium reached by the entire system at each point in time.

III. Assumptions and Conventions

Macroeconomic:

-GNP is assumed to grow at a rate of 2.7 percent between 1980-1985, 2.9 percent between 1985-1990, 2.5 percent between 1990-1995, and 2.0 percent between 1995-2030, as compared to the overall GNP growth of 3.2 percent experienced during the 1970s.

-The rate of inflation, as defined by changes in the GNP price deflator index, is projected to decline over the forecast period. The deflator index is assumed to be 8.2 percent between 1980-1985, 6.8 percent between 1985-1990, and 5.2 percent between 1990-1995. This implies a 6.7 percent average annual compound rate between 1980-1995, which can be compared to the 6.8 percent rate experienced by the economy between 1970-1980.

-Real disposable income per capita, an important factor in determining the demand of individual households for energy services, is assumed to grow at an average annual rate of 2.0 percent over the period 1980-1995. The comparable figure for the period 1965-1980 is 2.5 percent.

Utility Electricity:

-New non-nuclear technologies considered in the analysis are: low-Btu gas (from coal) combined cycle, fuel cells (supplied by oil and coal gasifiers), atmospheric and pressurized fluidized bed combustion, magneto hydrodynamics, geothermal, wind, solar thermal and photovoltaic, biomass, and ocean thermal energy conversion.

-The fast breeder reactor is assumed to be available in 2010.

-The output from fusion reactors is insignificant through 2020.

-Load patterns of electric power demand are represented by grouping power plants according to various load categories based on technology and costs of generation. As fuel prices change and new technologies are introduced, plants are loaded such that generating costs are minimized.

Resources:

-No price regulations are assumed.

-The prices of all petroleum products are assumed to be equal to the projected domestic refinery costs of products made from imported oil.

-Net exports of coal double by the year 2000 from their 1981 level of 3 quads and then remain constant through 2020.

-Refining of boiler fuel from coal and shale oil is assumed to cost 50 percent more than crude oil refining.

-Transportation costs vary among regions and are added to the cost of production before market prices are calculated. Distribution costs, which differ by fuel and by consuming sector, are then added to determine delivered costs.

Industrial and Commercial:

-New technologies accounted for in the industrial sector are: low or medium-Btu gas from coal, fluidized-bed combustion, geothermal, solar, cogeneration using fluidized bed combustion, gas engine, and electric heat pump to upgrade waste heat.

- Upper bounds are placed on cogeneration (no more than 50 percent of total indirect heat), geothermal, and coal (restricting it to uses not requiring clean heat).
- Commercial space and water cooling demands are considered together since water heating demands are a small fraction of total commercial energy demand.

Other:

- Detailed assumptions are made about the relative fuel efficiency and annual vehicle miles of cars, trucks, buses, aircraft, rail, and other types of transportation.
- The basic data and structure for the residential sector are from the Hirst residential demand model developed by the Oak Ridge National Laboratory.

IV. Projections

This section describes the projections generated by the LEAP model for the Energy Information Administration's 1981 Report to Congress. Unless otherwise specified, these projections correspond to the base or "Medium World Oil Price" case. The EIA report also presents results corresponding to "High Capital Costs for New Technologies," "Low Nuclear," and "High Nuclear" cases. The principal features of the longer term projections are changes in end-use energy consumption patterns (increases in industrial uses of coal and residential uses of renewables) and changes in energy production technologies (coal synthetic processes and new electricity generation sources, for example). The EIA report concludes that "these patterns, however, are all gradual adaptations to higher prices and to shifting sources of supply. They do not imply radical changes, as some analysts have forseen, such as the end of private automobiles and the stagnation of industrial growth. In this sense, the long-term projection is encouraging. It implies adequate amounts of energy, albeit at higher prices." (EIA, 1982)

In table 1 several aggregate results from the analysis are summarized. It can be seen from this table that oil and natural gas decrease in relative importance as supply sources throughout the forecast period. At

Table 1. Long Term Balance Between Energy Supply and Demand Projections, by Type of Energy and Sector, Mid-price case (Quadrillion BTU per year)

	Historical[a]	Projected				
	1980	1990	2000	2010	2020	2030
Domestic supply[b]						
Oil	21	20	21	21	17	13
Natural gas	20	18	18	16	15	12
Coal	19	27	41	56	77	101
Nuclear	3	8	11	15	18	20
Other[c]	5	7	11	15	19	24
Subtotal	68	80	102	123	146	170
Net imports						
Oil	13	12	8	4	3	2
Natural gas	1	1	1	0	0	0
Coal	-3	-4	-6	-6	-6	-6
Subtotal	11	9	3	-2	-3	-4
Total energy supply	79	89	105	121	143	166
Domestic demand[d]						
Residential	9	10	11	11	12	12
Commercial	7	6	7	7	8	8
Industrial	23	32	37	43	49	58
Transportation	19	18	19	19	19	20
Total end-use demand	59	66	74	80	88	98
Transmission losses, stock changes, and accounting errors.	20	23	30	41	55	68
Total energy demand	79	89	104	121	143	166

[a] Data from Monthly Energy Review (U.S. Department of Energy, November, 1981) and Natural and Synthetic Gas (Energy Data Report, U.S. Department of Energy, 1980) as cited in (U.S. Department of Energy, February, 1982).

[b] Includes unconventional and conventional sources.

[c] Includes hydropower, solar, geothermal, and biomass.

[d] Sectoral breakdown for 1980 differs from individual tables presented later because of inconsistencies in the original study.

Note: Totals may not add due to rounding.

the same time the contributions of other supply sources, particularly coal, become greater in relation to energy supply as a whole. Table 2 shows how the amounts supplied from various sources, taken as a percentage of total supply, are projected to vary through 2030.

Table 2. Composition of Primary Energy Supply Over Time[a]
(percentages)

	1980	1990	2000	2010	2020	2030
Oil	43	36	28	21	14	9
Natural gas	27	21	18	13	10	7
Coal	20	26	34	42	50	57
Nuclear	4	9	10	12	13	12
Other	6	8	10	12	13	15
	100	100	100	100	100	100

[a] Fuel categories include net imports, if any.

Not only do the relative shares of oil and natural gas drop markedly, but the proportion of these reduced shares that are met through the use of "unconventional" methods rises substantially. These unconventional methods, narrowly defined to include enhanced oil and gas recovery and oil from shale and shown in table 1 under the appropriate category, are also supplemented by increased production of coal-based synthetic fuels in meeting oil and gas demands. Table 3 contains the relevent projections on unconventional oil and gas recovery and synfuels production.

Table 3. Supply-Demand Balances for Unconventional Oil and Gas Recovery and Synfuels Production (Quads)

	1980	1990	2000	2010	2020	2030
Unconventional oil and gas production[a]						
Oil	.90	2.51	5.26	8.25	9.31	8.96
Natural gas	.95	2.23	4.70	6.58	8.79	7.60
Coal-based synthetic fuels[b]						
Liquids	0.0	.05	1.52	6.23	13.41	21.06
Gases[c]	0.0	.01	.12	.38	.750	1.45

Source: 1981 Annual Report to Congress (U.S. Department of Energy, 1982).

[a] Includes enhanced oil and gas recovery and oil from shale.

[b] Only the coal feedstocks used to produce these synfuels appear in the primary energy balance in table 1.

[c] Includes only high BTU synthetics.

Unconventional oil supplies are projected to compensate for the early declines in conventional domestic oil production through the year 2000. Oil from these sources is projected to grow moderately thereafter. Coal liquids technologies are projected to be insignificant contributors until 2000, but can be expected to grow substantially from then on as the oil price continues its projected escalation. Unconventional natural gas production is also projected to grow steadily, increasing from 2 quads in 1990 to 5 quads in 2000, and nearly 8 quads by 2030. The diminished demand for natural gas, coupled with the projected availability of unconventional natural gas, acts to reduce the projected need for much additional gas from coal. Coal gas synthetics are projected to grow from .01 quads in 1990 to 1.45 quads in 2030.

The demand side of the projections indicates that the distribution of these supplies within and between sectors changes in important ways over time. Table 4 shows that oil use by households can be seen to fall by nearly a factor of seven over the forecast period, the most dramatic drop in any of the supply categories. This is offset by substantial increases in electricity and solar. Residential consumption of solar energy increases twenty five-fold by 2030 and ranks behind only electricity and gas in terms of quads consumed.

Table 4. Residential Energy Demand by Source
(Quads)

	1980	1990	2000	2010	2020	2030
Oil	1.54	.98	.64	.45	.33	.23
Gas	4.90	4.13	4.00	3.70	3.34	2.85
Electricity	2.66	3.26	3.88	4.26	4.54	4.60
Solar	.08	.39	.69	1.05	1.47	2.06
Distrib. photo-electric	0.0	*	.03	.16	.39	.63
Geothermal	0.0	*	.04	.20	.42	.59
Coal	.26	.22	.16	.16	.15	.15
LPG	.52	.61	.44	.35	.34	.31
Biomass	.58	.76	.96	1.02	.9	1.01
Total	10.55	10.35	10.84	11.37	11.97	12.43

* Demand is between 0 and .01 quads.

A similar pattern of changes in demand can be seen in the commercial sector. Again the trend is towards decreased use of fossil fuels and increased use of electricity, although demand for natural gas increases through the year 2000 before beginning to drop off at a moderate rate. Both solar and geothermal capture an increasing portion of demand, with geothermal penetrating the market more slowly but later overtaking solar.

In the industrial sector the trends are somewhat more ambiguous. While increased use of electricity dominates the projections, there are also increases in demand for light oil, coal, and LPG gas. Biomass fuels are expected to meet an increasing share of demand, providing approximately 3 quads by 2030.

Table 5. Commercial Energy Demand by Source
(Quads)

	1980	1990	2000	2010	2020	2030
Oil	1.42	1.13	.82	.57	.42	.32
Natural gas	2.37	2.54	3.00	2.81	2.41	2.00
Electricity	1.76	2.24	2.87	3.55	4.29	5.05
Solar	*	.04	.08	.14	.23	.35
Geothermal	0.0	.01	.08	.18	.28	.39
Total	5.55	5.95	6.85	7.25	7.63	8.11

Table 6. Projections of Industrial Energy Demand by Source
(Quads)

	1980	1990	2000	2010	2020	2030
Oil	8.25	8.04	8.64	9.63	11.18	13.45
Gas	8.74	9.35	9.26	8.68	8.00	7.07
Electricity	2.79	3.85	5.17	6.56	8.31	10.51
Coal[a]	3.97	5.61	8.61	11.95	14.75	17.98
Solar[b]	0.0	0.0	*	*	.01	.01
Geothermal	*	.04	.14	.27	.44	.65
Biomass	1.32	2.20	2.40	2.56	2.76	3.03
Other[c]	1.98	2.45	3.11	3.70	4.33	5.07
Total	27.05	31.54	37.33	43.35	49.78	57.77

[a] Includes metallurgical coal.

[b] With gas backup.

[c] Includes lubes, waxes, asphalt, road oil, etc.

For transportation it is helpful to think in terms of fuel use by mode in addition to fuel use by fuel type. The basic data for this sector are contained in tables 7 and 8.

Table 7. Projections of Transportation Energy Demand by Source (Quads)

	1980	1990	2000	2010	2020	2030
Oil	17.96	17.53	17.83	17.83	18.41	19.16
Electricity	0.0	.03	.11	.16	.20	.22
Gas pipeline transport	.61	.64	.64	.61	.56	.48
Total	18.58	18.19	18.57	18.60	19.17	19.86

The two key determinants of these projections, vehicle miles traveled and fuel efficiency, change significantly over time but tend to offset each other. In the case of light trucks, for example, vehicle miles traveled increases from 254 billion miles in 1980 to 605 billion miles in 2030, which might be expected to dramatically raise fuel consumption in that sector. Simultaneously, however, the average miles-per-gallon for new light trucks is projected to increase from 13.18 in 1980 to 32.66 in 2030. These two developments cancel each other out and fuel consumption actually drops slightly after the year 2000. It can be seen that for automobiles the increased fuel efficiency (15.2 mpg in 1980 compared with 44.6 in 2030) more than offsets the increased miles traveled (1108 billion miles in 1980 compared with 2126 billion miles in 2030) resulting in a substantial drop in energy consumption for that sector.

Table 8. Transportation Energy Demand by Mode (Quads)

	1980	1990	2000	2010	2020	2030
Automobile (oil)	9.11	7.63	6.86	6.14	5.79	5.51
Automobile (elect.)	0.0	.03	.11	.16	.20	.22
Light truck	2.41	2.52	2.55	2.44	2.40	2.32
Aircraft	1.87	2.06	2.37	2.65	3.03	3.47
Bus	.11	.12	.14	.13	.13	.12
Pass. Rail	.07	.07	.07	.06	.06	.05
Heavy truck	2.63	3.06	3.49	3.83	4.18	4.64
Freight rail	.63	.71	.83	.92	1.03	1.13
Marine	1.14	1.35	1.53	1.65	1.79	1.92
Gas pipeline transport.	.61	.64	.64	.61	.56	.48
Total	18.58	18.19	18.57	18.60	19.17	19.86

Given the trend towards increased demand for electricity exhibited in the projections, it is appropriate to look at the primary fuels consumed by utilities to generate the electricity. These primary fuel requirements are shown in table 9.

Table 9. Consumption of Primary Fuels by Electric Utilities (quads)

	1980	1990	2000	2010	2020	2030
Oil	2.86	.94	.53	.20	.20	.21
Gas	3.20	2.11	1.24	.90	.89	1.00
Coal	12.05	16.87	22.92	25.26	29.04	33.25
Nuclear	2.75	7.70	10.50	15.49	17.89	19.98
Renewables[a]	3.24	3.55	4.71	6.28	8.52	10.78
Total	24.10	31.17	39.90	48.13	56.54	65.22

[a] Includes biomass, solar, "OTEC", geothermal, wind, and hydro.

Electricity will largely be derived from nuclear, coal, hydropower, and, increasingly, from unconventional sources, such as geothermal, solar, and cogeneration. Utilities are projected to use little gas or oil by 2020 compared to current use of oil and gas which generates 26 percent of electricity. Coal now supplies 51 percent, nuclear 11 percent, and hydropower 12 percent. By 2020, it is projected that nuclear will account for 32 percent, coal for 51 percent, and renewable energy sources, including hydropower, for 15 percent. Although the growth rates of electricity generation of 2.5 percent per year for 1960-2000 and 1.8 percent for 2000-2020 are moderate by historical standards, a continually increasing fraction of total primary energy is consumed to provide electricity. During the period 1985 to 2000, electricity is projected to substitute for many conventional oil and gas technologies. The trend slows but continues until 2020. By 1990, utility electricity accounts for 14 percent of net energy consumed, and this grows to 16 percent by 2000 and 20 percent, or 17 quadrillion Btu, by the year 2020.

The longer term energy patterns are generally characterized by:

- oThe shift away from oil and gas in all sectors except transportation and petrochemicals
- oThe shift toward coal in utilities and many industrial applications
- oThe increased growth of nuclear electric generation
- oThe continued trend toward electrification of the energy system
- oThe growth of coal-based liquids
- oThe continued growth in the use of renewable technologies

V. Comments

The model's strict attention to detail is both an advantage and a disadvantage. While the fine disaggreation within fuels and demand categories is useful, it is necessary to develop and maintain data on thousands of parameters in order to work with the model. The Energy Information Administration, in fact, "shelved" the LEAP model at least temporarily due to budget constraints.

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Appendix C

Summary of ORNL National Energy Perspective Study Projections

I. Background

The National Energy Perspective study was undertaken to guide ORNL in establishing priorities for research and development over the coming years. The overall orientation of the work is somewhat different than that of some of the studies discussed in this report. While projections of future outcomes are based largely on trend analysis (or some variation of it), the authors begin by outlining a set of energy planning objectives (for example, security from disruptions of foreign supplies) and then examine the "real-world" situation to see what strategies will be most effective in meeting those objectives.[1] An important aspect of this latter phase was the development of various demand and supply projections, which are discussed in some detail in this summary.

II. Methodology

There is little effort in the study to rely on detailed models of the economy, and the framework used is not designed to analyze how energy markets respond to changing prices, levels of demand, and quantities supplied. It is explicitly assumed that energy demand can be characterized in terms of its relationship with the future growth of the economy.

The authors comment that "...in this investigation, as in most energy studies, certain specific goals and principles form the foundation for the conclusions about an appropriate energy strategy." The goals underlying the strategy outlined in the ORNL study include:

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1. Toward the end of their report, the authors comment that "the strategy examined in the foregoing analysis is not an exact blueprint for the entire 1980-2020 time frame." They add, however, that "given sufficient time, all of the steps outlined in this report probably will be undertaken because of forces in the market" (emphasis added).

- A reduction of oil imports to 20 percent of total U.S. oil use by 2000, and eventual elimination of them;
- Maintenance of the capability of the U.S. energy system to support an annual growth rate in per capita GNP of 2.00 percent;
- Retention of existing lifestyles, including continued use of personal transportation and dispersed patterns of living;
- Maintenance of overall environmental quality.

The authors suggest that the following steps can be taken to meet these objectives and include them in their analyses of future demands and supplies.

- Acceleration of fuel substitution in electric utilities, space and water heating, industrial steam raising, and process heating;
- Improvements in end-use efficiency emphasizing transportation, space and water heating, and industry;
- Acceleration of domestic energy production to allow reductions in oil imports.

III. Assumptions

The key assumptions underlying the ORNL demand projections are listed in table 1. These can be grouped into two broad categories consisting of those which are varied to generate the alternative scenarios and those which are held constant across the scenarios. The assumptions that are held constant (for example, GNP) are the ones which determine the level of demand for various energy services, while those which are varied (for example, energy intensities for truck transport) determine the alternative amounts of energy required to provide the fixed level of services.

Not surprisingly, historical data indicate that industrial output is closely related to GNP, so the postulated future GNP levels given in table 1 are the basic assumptions driving energy demand for the industrial

Table 1. Summary of Projection Assumptions

	1977	1980	1985	1990	1995	2000	2010	2020
Macroeconomic								
Population (10^6)[a]	216.8	--	233.0	244.0	--	260.0	275.0	290.0
GNP (10^9 1972 dollars)[b]	1,337.0	--	1,684.0	1,947.0	--	2,528.0	3,260.0	4,191.0
Per capita GNP (1972 dollars)[c]	6,167.0	--	7,226.0	7,978.0	--	9,725.0	11,854.0	14,450.0
Transportation energy intensities[d]								
Cars	1.0	--	.75-.81	--	.57-.65	.45-.56	.34-.40	.31-.37
Trucks	1.0	--	.83-.86	--	.68-.74	.63-.68	.54-.60	.47-.54
Air	1.0	--	.84-.89	--	.71-.78	.65-.74	.57-.66	.50-.60
Water	1.0	--	.98	--	.95	.93	.90	.87
Residential housing stock[e]								
Single family	--	51.9	--	61.1	--	69.4	74.2	--
Multifamily	--	24.2	--	31.7	--	37.6	43.5	--
Mobile homes	--	3.6	--	5.6	--	7.4	9.0	--
Total	--	79.7	--	98.4	--	114.4	126.7	--
New appliance energy intensities[d]								
Electric space heating	--	1.0	--	.88	--	.75	.66	--
Gas space heating	--	1.0	--	.81	--	.76	.73	--
Oil space heating	--	1.0	--	.84	--	.78	.75	--
Electric water heating	--	1.0	--	.85	--	.85	.85	--
Gas water heating	--	1.0	--	.80	--	.79	.75	--
Oil water heating	--	1.0	--	.81	--	.81	.79	--
Electric air conditioning	--	1.0	--	.75	--	.75	.70	--
Commercial floor space (10^9 ft^2)[e]	--	31.2	--	42.6	--	57.3	77.9	--

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[a] Figures from U.S. Bureau of the Census, Department of Commerce, Series II (Washington, D.C, Dept. of Commerce, 1997).

[b] Based on assumed 2 percent annual rate of growth in real per capita GNP together with population growth projections.

[c] Corresponds to 2 percent annual growth. This rate was considered by the authors to be both reasonable in light of historical trends and necessary in light of the objectives they feel are fundamental to a sound energy policy.

[d] Measures relative improvement in efficiency since base year (1977 for transportation sector and 1980 form residential and commercial sector). A value of 0.50 in 2000 means that half the energy required in the base year to deliver a particular energy service is required in 2000 to deliver the same service.

[e] Data taken from John Gibbons and coauthors, Alternative Demand Futures to 2010 (Washington, D.C., National Academy of Sciences, 1979).

sector.[2] Other important assumptions for this sector concern the formation of new capital stock, retrofits of older stock, and the impact of these changes on energy requirements.

Turning to the transportation sector, the number of cars on the road is assumed to increase at a fixed rate of 2.8 million per year, with an annual average of 11,000 miles traveled per car. Miles traveled on other noncommercial ground modes and buses increase in proportion to the population. Miles traveled by air and ton-miles traveled by commercial ground modes increase in proportion to GNP. Assumptions about the relative intensities of different modes are used to generate the high and low scenarios for this sector.

The assumptions most directly affecting the projections of residential and commercial buildings' energy demand are the size and composition of the housing stock and the total square feet of commercial building floor space. Annual additions of new units to the housing stock are assumed to average approximately 2.7 million between 1980 and 2020, with net additions (new units minus units retired from stock) averaging 1.3-1.8 million per year. Only a slight change in the composition of the stock is assumed, which is a small (7 percent) decrease in the proportion of single family homes and a corresponding increase in the proportion of multifamily homes. Annual net additions of commercial floor space of between 1.1 and 2.0 billion square feet are assumed (the higher figure applies to later years), as measured against the 1980 total of 31.2 billion square feet.

IV. Projections

Total energy demand is taken as the sum of industrial, transportation, and residential/commercial demands. Table 2 summarizes the relevant demand projections for the industrial sector under two scenarios. The relative composition of this projected demand by fuel is given for the low scenarios in table 3. The big drop in industrial petroleum demand is compensated for

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[2] Data presented by Dunkerley (1980), however, suggest that it would be misleading to tie growth in industrial energy demand directly to growth in industrial output since the amount of energy required per unit of industrial output is falling steadily.

Table 2. Projected Industrial Energy Demand by Fuel (quads)

Fuel	1979[a]	1990	2000	2010[b]	2020
Low[c]					
Petroleum	8.9	5.6	4.1	4.7	5.3
Gas	8.6	9.7	12.3	12.6	12.9
Coal	3.6	6.9	7.1	8.2	9.2
Electricity[d]	2.9	4.3	5.1	5.8	6.4
	24.0	26.5	28.6	31.3	33.8
High[e]					
Petroleum	8.9	7.1	5.7	6.0	6.3
Gas	8.6	10.4	11.5	13.6	15.7
Coal	3.6	7.1	8.9	10.0	11.0
Electricity[d]	2.9	4.6	5.5	6.5	7.5
	24.0	27.9	31.6	36.1	40.5

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[a] 1979 data from U.S. Department of Energy, Monthly Energy Review (Washington, D.C., U.S. Government Printing Office, November 1980).

[b] Results for 2010 were not reported by authors. They represent a simple linear interpolation (rounded off) between 2000 and 2020 data.

[c] Based on continuation of historical (1950-1970) 1.7 percent annual decline in industrial end-use energy intensities. (Note: The average annual decline in intensities during the mid-1970s was substantially greater--about 5.5 percent--but the authors contend that such rates cannot be maintained because the actions taken to achive them were one-time opportunities.)

[d] Throughout this paper electricity demand by end-use sectors is measured in terms of delivered energy. The primary energy required to generate this electricity is presented later and used to calculate aggregate energy demand.

[e] Assumed that limited capital availability of new equipment and processed, allowing energy intensities to decline at a rate of only 1.3 percent per year.

Table 3. Composition by Fuel of "Low" Industrial Energy Demand Projections[a] (percent)

Fuel	1979	1990	2000	2010	2020
Petroleum	37	21	14	15	16
Gas	36	37	43	40	38
Coal	15	26	25	26	27
Electricity	12	16	18	19	19
	100	100	100	100	100

[a] Fuel composition over time for the high scenario projections is similar. Low scenario results are presented here since the assumptions underlying them are tied more closely to historical trends.

by fairly substantial increases in coal and, to a lesser extent, electricity demand. The proportionate demand for gas remains stable over the forecast period.

Table 4 presents an analogous summary of projected demands for the transportation sector. Although the projected growth in demand for transportation services is substantial, increases in efficiency result in only slight growth in transportation energy demand.

Demand projections for the final category to be considered--residential and commercial buildings--are summarized in table 5. Although there are substantial increases in housing stock and commercial floor space included in the projections, end-use energy demand shows only modest growth even in the high scenario because of efficiency gains in new units and retrofits of existing ones. Relative changes in the composition by fuel projected for residential and commercial energy demands under the low scenario are shown in table 6. These results are somewhat different than those for the industrial sector. Oil drops out of the picture entirely and gas, which was projected to maintain a stable share of industrial energy demand, also loses a large portion of the residential and commercial demand. Electricity captures 73 percent of demand by 2020, compared to the 19 percent share it is projected to hold in the industrial sector at that

Table 4. Projected Transportation Energy Demand by Fuel

Fuel	1979	1990	2000	2010[a]	2020
Low[b]					
Petroleum	19.2	18.8	18.2	19.2	20.2
Gas[c]	0.5	0.5	0.5	0.5	0.5
Total	19.7	19.3	18.7	19.7	20.7
High[b]					
Petroleum	19.2	20.1	20.8	21.9	22.9
Gas[c]	0.5	0.5	0.5	0.5	0.5
Total	19.7	20.6	21.3	22.4	23.4

[a] Results for 2010 not reported by authors. They represent a simple linear interpolation between 2000 and 2020 data.

[b] Scenarios differentiated by assumed energy intensities for various modes. The underlying demand for each mode is held constant across both scenarios.

[c] Pipeline transport demand is considered fixed over the projection period.

time. Although the solar and other category is expected to increase its demand share six-fold, it still serves only 6 percent of demand by 2020.

The demand summaries for the industrial and residential and commercial sectors include electricity, a secondary energy source. The primary sources used by utilities to generate this electricity are listed in table 7, and the relative composition of utility primary energy in the low scenario is outlined in table 8. Oil and gas usage drops off quite sharply until 1990 and then declines at a moderate pace through 2020. Nuclear generation increases through 2000 and then levels off, while coal remains fairly stable for the duration of the forecast. The reasons for the sharp drop in hydroelectric and geothermal generation are not explained by the authors.

Energy demand for the economy as a whole is, of course, found by adding across each of the individual sectors, which is done in table 9. The relative composition of this aggregate demand is shown in table 10 for the low scenario.

The main difference between these proportions and those in the high scenario is the timing of the substitution of electricity for gas. In both the industrial and residential and commercial sectors there is a more rapid shift to electricity, at the expense of gas, in the high scenario. In terms of the primary sources listed in table 9, this shows up as a proportionately higher level of demand for coal in the high scenario during the 2000-2010 period and a proportionately lower demand for gas. By 2020, however, the shift to electricity is well underway in the low scenario and the proportions are similar in both scenarios.

Table 5. Projected Residential and Commercial Buildings Energy (quads)

Fuel	1979	1990	2000	2010[a]	2020
Low[b]					
Gas	7.8	5.7	6.0	5.2	4.4
Oil	5.8	1.6	0.5	0.3	0.0
Electricity	4.2	8.7	10.3	12.8	15.3
Solar and Other[c]	0.2	0.6	0.9	1.1	1.3
Total	17.9	16.6	17.7	19.4	21.0
High[d]					
Gas	7.8	6.4	4.8	4.9	4.9
Oil	5.8	1.8	0.6	0.3	0.0
Electricity	4.2	10.7	15.2	15.8	16.3
Solar and Other[c]	0.2	0.8	1.1	1.3	1.5
Total	17.9	19.7	21.7	22.3	22.7

[a] Interpolation, not reported by authors.

[b] Corresponds to an "aggressive" conservation program including various standards for new buildings, retrofits, and appliance efficiencies.

[c] For 1979, this category consists mainly of coal and a negligible amount of solar; after 1990, it is mainly active solar hot water heating. Space heating demand reductions brought about by passive solar heat gain were accounted for in the demand analyses and are not reported here.

[d] Corresponds to a "moderate" conservation program including only building thermal integrity standards and about half the residential retrofits assumed in the low scenario.

Table 6. Composition by Fuel of "Low" Residential and Commercial Buildings Energy Demand Projections[a] (percent)

Fuel	1979	1990	2000	2010	2020
Gas	44	34	34	26	21
Oil	32	10	3	2	0
Electricity	23	52	58	66	73
Solar and Other	1	4	5	6	6
	100	100	100	100	100

[a] Fuel composition over time for the high scenario projections is similar, although there is a more rapid shift to electricity and consequently lower demand, on both an absolute and relative basis, during the 2000-2010 period.

Table 7. Consumption of Primary Energy by Electric Utilities (quads)

Fuel	1979[a]	1990	2000	2010[b]	2020
Low					
Coal	11.3	22.0	25.1	30.5	35.9
Oil	3.6	2.0	1.4	1.5	1.6
Gas	3.6	1.7	1.4	1.5	1.6
Nuclear	2.7	9.8	17.6	20.9	24.1
Hydro and geothermal	3.2	1.2	1.3	1.5	1.7
Total	24.4	36.7	46.6	55.9	64.9
High					
Coal	11.3	22.0	37.3	38.9	40.5
Oil	3.6	2.0	1.4	1.7	2.0
Gas	3.6	1.7	1.4	1.7	2.0
Nuclear	2.7	9.8	21.3	23.5	25.6
Hydro and geothermal	3.2	1.2	1.3	1.5	1.7
Total	24.4	36.7	62.7	67.3	71.8

[a] Data from U.S. Department of Energy, Monthly Energy Review (Washington, D.C., U.S. Government Printing Office, November 1980).

[b] Interpolation, not reported by authors.

Table 8. Relative Composition of Electric Utility Primary Energy Consumption, Low Scenario (percent)

Fuel	1979	1990	2000	2010	2020
Coal	46	60	54	54	55
Oil	15	5	3	3	2
Gas	15	5	3	3	2
Nuclear	11	27	37	37	37
Hydro and geothermal	13	3	3	3	2
	100	100	100	100	100

Table 9. Aggregate Demand for Energy by Source (quads)

Fuel	1979	1990	2000	2010	2020
Low					
Petroleum	37.5	28.0	24.2	25.7	27.1
Gas	20.5	17.6	20.2	19.8	19.4
Coal	14.9	28.9	32.2	38.7	45.1
Nuclear	2.7	9.8	17.6	20.9	24.1
Hydro and geothermal	3.2	1.2	1.3	1.5	1.7
Solar	0.2	0.6	0.9	1.1	1.3
Total	79.0	86.1	96.4	107.7	118.7
High					
Petroleum	37.5	31.0	28.5	29.9	31.2
Gas	20.5	19.3	18.2	20.7	23.1
Coal	14.9	29.1	46.2	48.9	51.5
Nuclear	2.7	9.8	21.3	23.5	25.6
Hydro and geothermal	3.2	1.2	1.3	1.5	1.7
Solar	0.2	0.8	1.1	1.3	1.5
Total	79.0	90.9	116.6	125.8	134.6

Table 10. Relative Composition of Aggregate Demand in the Low Scenario (percent)

Fuel	1979	1990	2000	2010	2020
Petroleum	48	33	25	24	23
Gas	26	21	21	18	17
Coal	19	33	34	36	38
Nuclear	3	11	18	20	20
Hydro and geothermal	4	1	1	1	1
Solar	--	1	1	1	1
Total	100	100	100	100	100

V. Comments

The ORNL National Energy Perspective study undoubtedly provides a useful basis for looking at certain domestic energy policy issues. The straightforward approach taken by the authors in developing their projections keeps the reader grounded in the "real world" and allows the reasoning behind the various steps taken to be tracked in some detail. The study's main strength appears to be its use of appropriate data and analysis to set the stage for developing policy responses to emerging energy issues. Projections are explicitly contingent on achievement of certain policy goals, such as eventual elimination of oil imports. Thus, if attainment of those goals is considered questionable, the value of the forecasts is reduced. In addition, the analysis is intentionally and unabashedly normative, although the authors contend that the market will eventually behave in a manner consistent with the strategy they propose.

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Appendix D

Summary of the IEA/ORAU Long-Term Global Energy Model

I. Background

The Institute for Energy Analysis of Oak Ridge Associated Universities has developed, as part of a larger effort concerned with the accumulation of carbon dioxide (CO_2) in the atmosphere, a long-term global framework for energy assessment. Increased concentrations of atmospheric CO_2 have been linked to fossil fuel combustion and the estimates of future patterns of energy use generated by the model are being used to learn more about the potential magnitude of the CO_2 problem in the decades ahead. The model is designed to provide a "consistent, conditional representation of economic, demographic, technical, and policy factors as they affect energy use and production." Although the global coverage of the model necessitates a good deal of aggregation, the United States is broken out as a separate region and supplementary results obtained from the authors have allowed us to examine the projections relating to the United States in some detail.

II. Methodology

The model's very long time horizon (projections are currently being carried out to 2050), together with its global coverage, require that a less elaborate theoretical structure be developed than is common in short- to mid-term models. Energy demand for each primary fuel category[1] is developed for each region[2] separately. Five major exogeneous inputs determine energy demand: population, economic activity (GNP), technological change, energy prices, and energy taxes and tariffs. A set of energy flow accounts for each region tracks the conversion of primary rules into their secondary forms. These fuels are then consumed by end-use sectors (for the United States these are Industrial, Residential and Commercial, and Transportation) to produce energy services. The mix of secondary fuels used to meet the demand for energy services is determined by the relative costs of providing the services using each alternative. The demand for fuels to provide electric power is then determined by the relative costs of production, as are the shares of oil and gas transformed from coal and biomass. Primary energy demands are then calculated from technological parameters.

The supply of resources depends on geology and various institutional factors. The supply of unconstrained sources depends on the technology description (represented by a conventional supply schedule) and prices. The supply and demand components each generate energy supply and demand estimates based on exogenous input assumptions and energy prices. Since it is unlikely that such independently determined prices will lead to a balance between supply and demand, the energy balance component of the model iteratively selects prices which, after successive attempts, bring energy markets into balance within a prespecified bound.

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[1] These include oil (conventional, enhanced recovery, shale, and tar sands), gas (conventional and non-conventional), solids (coal and biomass), nuclear, resource constrained renewables (hydroelectric, geothermal), and solar (solar electric, wind, tidal, ocean thermal conversion, fusion, and other "advanced renewable technologies").

[2] These include USA, OECD West, OECD Asia, Centrally Planned Europe, Centrally Planned Asia, Middle East, Africa, Latin America, South and East Asia.

III. Assumptions

The U.S. population is assumed to grow at an overall rate of .4 percent annually from 1975 to 2020, although the rates observed between any two benchmark years vary. The overall growth rate for U.S. GNP is set at 2.0 percent. The resulting population, GNP, and per capita GNP are shown in table 1.

Table 1. Assumed Population, GNP, and Per Capita GNP

	1975	2000	2025	2050
Population (10^6)	213.93	254.36	281.74	288.16
Real GNP (10^9 \$ U.S. 1975)	1,519.89	2,852.83	4,591.59	6,847.10
Real Per Capita GNP	7,104.61	11,215.71	16,297.26	23,761.00

Price elasticities of demand are -.8 for the industrial sector, -.9 for the residential and commercial sector, and -.7 for the transportation sector. These elasticities apply to secondary energy and are held constant over time.

The important supply side assumptions are estimates of the resource base for constrained supply technologies and the costs of each alternative source.

Table 2. Resource Base and Cost Assumptions for Alternative Supply Sources

Resources[a] (quads)	
Conventional oil	1522.27
Conventional gas	1500.47
Hydro	1.73
Costs ($1975 per million BTU)	
Conventional oil[b]	1.90
Conventional gas[b]	.95
Unconventional oil	3.65
Unconventional gas	3.50
Synthetic oil[b]	4.31
Synthetic gas[b]	3.13
Coal	.25
Biomass (waste)	0.0
Biomass (energy farms)	2.00
Electric (oil)[c]	4.29
Electric (gas)[c]	4.27
Electric (coal)[c,d]	6.51
Electric (hydro)[e]	5.80
Electric (nuclear)[e,f]	8.71
Electric (solar)[e,f]	18.96

[a] These values include cumulative production or cumulative installed capacity, as appropriate, and remaining resources.

[b] Implicitly assumed that the full resource can eventually be produced at producer costs equal to or less than this amount.

[c] Nonfuel costs.

[d] Assumes scrubbers installed.

[e] Includes transmission losses.

[f] Varies by region and over time; reported costs are for low-cost regions.

IV. Projections[3]

World oil prices, (in real terms) are projected to fall 9 percent by 2000 from the $34 per barrel level prevailing at the end of 1981.[4,5] After 2000, oil prices increase 36 percent before nearly leveling off after 2025. The post-2000 increases are caused by gradually increasing demand coupled with reduced production of conventional oil, which together induce a switch to the more expensive synthetic oil and shale oil. Gas prices are somewhat more difficult to summarize because of the large transport cost wedge between importers and exporters. The model projects world gas prices (producer prices in exporting regions) to fall through 2000 from present levels, but gas prices in consuming regions to rise. The authors conclude that exporting regions will tend to consume domestic gas rather than exporting it as a result. Beyond 2000 the world price of gas rises rapidly, increasing by a total of 450 percent between 2000 and 2050.

Coal prices show relatively little movement over the forecast period, and the exhaustion of high-grade low-cost coal is not considered an important contributing factor to the coal price increases that do occur on a global level. Although coal production expands at an overall rate of 2.9 percent annually, this expansion does not generate major pressure on coal costs. The stability of coal costs combined with the availability of nuclear power combine to result in relatively stable electricity prices, although modest increases are observed in some world regions as the share of electricity generated from low-cost hydropower drops.

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[3] Many of the results discussed in this section are based on supplementary unpublished data obtained from Dr. Jae Edmonds.

[4] The price shocks initiated in 1979 make this decrease misleading; the forecast prices are actually 75 percent greater than the base year (1975) prices.

[5] Domestic energy prices are expected to roughly follow, in direction if not in absolute magnitude, the trends reported here for world prices. (Personal communication from authors.)

The authors of the study caution that the breakdown for secondary energy demand by the three end-use sectors is not an important part of their study and, thus, has not received a great deal of attention. Still, they are presented here for the use of the reader. The general trend, except in the transportation sector where fuel choices are strictly constrained, is away from oil and gas and towards electricity and direct coal. This is demonstrated convincingly in the case of the industrial sector, as shown in Tables 3 and 4.

Table 3. Projected Secondary Energy Demand for the Industrial Sector (quads)[a]

	1975	2000	2025	2050
Oil[b]	3.57	3.38	2.31	2.61
Gas[b]	7.42	3.85	1.90	1.14
Coal[c]	2.35	2.35	5.12	4.84
Electricity[d]	2.45	5.55	7.50	9.61
Total	15.79	15.13	16.83	18.20

[a] Converted from exajoules to quads using Q = 1.055 EJ.

[b] Synthetics are included in these categories.

[c] Net of coal diverted to synthetics production.

[d] Delivered (net of transmission losses).

Note: Authors advise that sectoral breakdown were only a byproduct of the study and are not the result of sophisticated calculations.

Table 4. Composition of Industrial Energy Demand Over Time (percent)

	1975	2000	2025	2050
Oil	23	22	14	14
Gas	47	25	11	6
Coal	15	16	30	27
Electricity	15	37	45	53
Total	100	100	100	100

A similar trend of fuel substitution is projected for the residential and commercial sector. Although the absolute quantities demanded of both oil and gas increase slightly, which does not happen in the industrial sector, their relative shares drop markedly due to substantial increases in the demand for electricity. These results are documented in tables 5 and 6.

Table 5. Projected Secondary Energy Demand for the Residential and Commercial Sector (quads)[a]

	1975	2000	2025	2050
Oil	5.71	5.55	5.91	7.91
Gas	8.99	9.81	10.25	10.32
Coal	.21	.28	.67	.84
Electric	4.39	9.60	15.98	23.12
Total	19.31	25.24	32.81	42.19

[a] See table 3 for definitions and conventions.

Note: Authors advise that sectoral breakdown were only a byproduct of the study and are not the result of sophisticated calculations.

Table 6. Composition of Residential and Commercial Energy Demand Over Time (percent)

	1975	2000	2025	2050
Oil	30	22	18	19
Gas	46	39	31	24
Coal	1	1	2	2
Electric	23	38	49	55
Total	100	100	100	100

Projections for the transportation sector contain no dramatic fuel shifts, although the share of electricity demand increases insignificantly. Comparisons with several other studies indicate that these projections may be somewhat high. Whether this is due to higher estimates of demand for travel or lower estimates of increases in efficiency is unclear.

Table 7. Secondary Energy Demand for the Transportation Sector (quads)[a]

	1975	2000	2025	2050
Oil	18.84	28.49	38.72	56.08
Electric	.02	.04	.08	.10
Total	18.86	28.53	38.80	56.18

[a] See table 3 for definitions and conventions.

Note: Authors advise that sectoral breakdown were only a byproduct of the study and are not the result of sophisticated calculations.

The sectoral demands of each sector can be added up to find the aggregate demands for energy in each of the benchmark years. Before this is done, however, it is helpful to express the demand for electricity in terms of the "primary"[5] sources used to generate it.

Table 8 indicates the fossil fuel equivalents (on the basis of average efficiency and conversion losses) of the sectoral electricity demands listed in tables 3, 5, and 7.

Table 8. Electric Utility Generation by Source (quads)[a]

	1975	2000	2025	2050
Oil	3.83	1.38	3.56	6.84
Gas	3.69	4.45	8.68	10.86
Coal	10.51	25.91	29.00	37.10
Nuclear[b]	2.05	14.37	30.32	47.47
Solar[b,c]	0.0	.04	3.14	4.30
Hydro[b]	3.62	5.19	5.78	5.91
Total	23.70	51.35	80.48	112.48

[a] See table 3 for definitions and conventions.

[b] Reported in fossil equivalents based on average fossil fuel efficiency for conversion to electricity.

[c] Passive solar, like conservation, is treated as a reduction in end-use demand.

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[5] This is a somewhat relaxed definition of "primary energy" since oil and gas categories include synthetics and coal is net of the quantities diverted to synthetic.

A look at the relative composition of electric utility primary demand reveals that major shifts in the mix of sources used to generate electricity are anticipated. Oil and gas, which in 1975 accounted for 31 percent of primary demand, account for only 16 percent in 2050 due to increasing costs relative to other electricity producing technologies. By 2050 the most important sources for electricity generation are nuclear and coal. The rapidly increasing share of nuclear results from continued market penetration and low relative costs.[6] Although the absolute demand for hydroelectricity increases, its relative share falls since resource constraints prevent it from increasing at the pace of nuclear. Solar technologies begin to penetrate the market after 2000, but it appears unlikely that photovoltaics will be used to generate much electricity except in very specialized uses.

Table 9. Relative Composition of Electricity Generation (percent)

	1975	2000	2025	2050
Oil	16	3	4	6
Gas	15	9	11	10
Coal	44	50	36	33
Nuclear	9	28	38	42
Solar	0	0	4	4
Hydro	15	10	7	5
Total	100	100	100	100

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[6] The framework used in the analysis considers nuclear as a generic technology and is not suitable for projecting, say, the market penetration of fast breeders relative to light water reactors. Fusion is explicitly excluded because it is still an unproven technology.

The sectoral demands for oil gas, and coal from tables 3, 5, and 7 together with the refinable equivalents of electricity generation from table 8 can now be totaled to find estimates of aggregate demand for primary energy. Since the energy balance component of the model iteratively adjusts prices until a supply-demand equilibrium is reached, the supply mix corresponding to these projections is calculated simultaneously by the model. These aggregate refinable energy balances are shown in table 10.

One of the most striking results in table 10 is the degree to which demands for oil and gas will be met through unconventional and synthetic production. In the case of oil, production from unconventional sources dominates supply by 2025 and allows the United States to become a net exporter of oil by 2050. Synthetic oil also penetrates an increasing proportion of the market, and by the end of the projection period more oil is produced synthetically than from conventional sources. Unconventional gas never makes more than a negligible supply contribution, but a full 88 percent of gas supplies in 2050 are produced synthetically. As with oil, by 2050 the United States is a net exporter of gas. Coal production is almost exclusively from conventional sources through 2050, but an increasing amount of this production is diverted to synthetic conversions.

V. Comments

The IEA/ORAU model should be considered an important part of our review of post-2000 energy projections primarily because of its very long time frame, its global coverage (while preserving detail for the United States), and, to a lesser extent, its recent vintage. On a more practical note, the model is inexpensive to work with and alternative scenarios are easily generated by varying parameters of interest, yet the model output provides an interesting level of detail for many long-term energy questions. The authors, however, do not hesitate to point out some of the

Table 10. Supply-Demand Balances for Refinable Energy (quads)

Aggregate Demand	1975	2000	2025	2050
Oil	31.95	38.83	50.50	73.44
Gas	20.10	18.11	20.81	22.32
Coal	13.07	28.54	34.79	42.78
Nuclear	2.05	14.37	30.32	47.47
Solar	0.0	.04	3.14	4.30
Hydro	3.62	5.19	5.78	5.91
Supply				
Oil				
Conv.	19.06	16.49	7.19	2.26
Unconv.	0.0	0.0	19.64	65.72
Synthetics	0.0	.32	4.86	8.24
Net imports	12.89	22.02	18.79	-2.80
Total	31.95	38.83	50.50	73.42
Gas				
Conv.	16.28	17.18	8.52	2.82
Unconv.	0.0	0.0	0.0	0.0
Synthetics	0.0	.09	2.54	19.54
Net imports	3.82	.83	9.75	-.04
Total	20.10	18.10	20.81	22.32
Coal				
Conv.	16.28	31.73	58.09	112.91
Unconv.	0.0	1.74	2.03	3.28
Synthetic conversions	0.0	-.81	-14.20	-46.87
Net imports	-3.21	-4.12	-11.24	-26.55
Total	13.07	28.54	34.78	42.78
Nuclear	2.05	14.37	30.32	47.47
Solar electric	0.0	.04	3.14	4.30
Hydro	3.62	5.19	5.78	5.91
Supply/demand balance	70.79	105.7	145.33	196.21

limitations they see with the model. For example, it looks exclusively at energy markets and the only feedback between energy and the rest of the economy is through GNP. The model is not designed to project variables such as the international balance of payments, interest rates, or terms of trade. Another limitation relates to the regional aggregation of the model. While the nine regions could be changed to some extent, there is little that can be done within the context of the model to disaggregate to significantly smaller geographical units. An analysis of energy supply and demand at the state level, for instance, would not be an appropriate application of the framework. Finally, the model was designed specifically for long-term analysis and is not suitable for projections extending out one quarter, or even one decade. Underlying the parameters of the model is an explicit assumption that capital stocks are malleable, which approximates reality only in the long-run.

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Appendix E

Summary of the CONAES Demand Projections

I. Background

The National Research Council, in an effort to guide policy development on emerging energy issues, established in 1975 a Committee on Nuclear and Alternative Energy Systems (CONAES) to learn more about how the nation's energy economy will evolve in the period 1985-2010. The demand aspects of the study focused on (a) expected ranges of energy demand as they relate to alternative sets of plausible "demand-shaping" assumptions, (b) technological opportunities for energy conservation, (c) the role of institutional and behavioral factors constraining or accelerating energy demand, and (d) the implications of findings for emerging policy issues. In dealing with these issues, the CONAES group sought to provide a "broad consistent exploration of several energy futures," rather than point estimates of the most likely outcomes.

II. Methodology

A three-tiered approach consisting of independent sector analyses, an integrating 40-sector model, and a supplementary econometric model was used by the CONAES demand panel. The sector analyses aggregated the economy into three categories (Residential and Commercial Buildings, Industry, and Transportation) and examined each separately to broadly determine how energy use would respond to the different scenario assumptions. Expert opinion, engineering analysis, and microeconomics were combined, as appropriate for the sector under consideration, to identify the unique problems and opportunities associated with each sector. While of value in and of themselves, various results from the sectoral analyses are also fed into an input-output model of the economy to capture the effects of interactions between the different sectors. For additional understanding, an econometric model was developed to study mid-term (1990) energy use and estimate in a rigorous manner the effects of changes in energy prices, population size, and real income. While the three alternative approaches used by the panel do not produce results that are strictly comparable, they are complementary and provide informal benchmarks which make it easier to spot anomolies.

III. Assumptions

The CONAES demand panel developed alternative scenarios by varying the assumptions made about future rates of economic growth and changes in energy prices. In addition, several sets of assumptions unique to each sector (for example, size and composition of the housing stock) were postulated as necessary. Estimates of future population growth were held constant across all scenarios.[1]

The Series II projection of the Census Bureau, which yields a national population of 279 million by 2010, was selected for use in the study.

Table 1. Census Bureau Population Projections Adopted by CONAES (millions)

	1975	1980	1990	2000	2010
Population	214.0	223.0	245.0	263.0	279.0

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Table 2 indicates the major assumptions underlying the four scenarios discussed below (a total of six scenarios were developed by the panel). The demand panel's report should be consulted for details about the sector specific assumptions. The range of possible energy prices and economic growth built into the four scenarios makes it possible to use the projections reported below to learn more about the impact of changes in these variables on energy consumption.

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[1] The authors point out that "implicit in the use of one (population) projection for all the scenarios is the assumption that population growth will be independent of energy prices and real income."

Table 2. Alternative CONAES Scenarios

Scenario	2010 Energy Prices[a]	2010 GNP	Average Annual GNP Growth Rate[b]
"Low Energy Costs"	1 x 1975 price	2 x 1975 GNP	2%
"Moderate Energy Costs	2 x 1975 price	2 x 1975 GNP	2%
"High Energy Costs"	4 x 1975 price	2 x 1975 GNP	2%
"High Economic Growth	2 x 1975 price	2.8 x 1975 GNP	3%

[a] Average for all forms of energy combined. Projections for specific fuels were also reported. Prices are national averages and are the prices seen by the user at the final stage of consumption in 1975 dollars. Price deregulation is implicit.

[b] Average growth rates for the entire 1975-2010 period. The actual growth rates observed during this period are:

	2% Average	3% Average
1975-1980	2.7%	4.7%
1980-1990	2.3%	3.5%
1990-2000	1.8%	2.6%
2000-2010	1.6%	2.1%

IV. Projections

This discussion emphasizes the results obtained from the integrating model because they are consistent across sectors and account for interactions between sectors, although they lack some of the detail found in the sector analyses. It is unfortunate that the panel only reported projections for the year 2010, but a simple linear interpolation can be used to crudely approximate the "trajectory" suggested by these results.

Table 3 outlines several of the alternative projections generated from the integrating model. For the purposes of this review the "Moderate Energy Costs" scenario will be treated as a base case, although the demand panel did not formally designate it as such. Comparing the results across different scenarios yields few surprises: the lower the price of energy or the greater the level of economic activity, the greater the quantity of energy demanded. However, within each scenario there are substantial

Table 3. Summary of Projections from CONAES Integrating Model (quads)

	Oil	Gas	Coal	Electricity	Total
1975, Historical					
Industry[a]	5.3	8.6	3.8	2.3	20.0
Buildings[a]	5.4	7.6	.2	3.6	16.8
Transportationa	16.7	.6	--	--	17.3
Total demand[a]	27.4	16.8	4.0	5.9	54.1
Conversion losses[b]	2.5	--	--	14.2	16.7
Primary Input	29.9	16.8	4.0	20.1	70.8
2010, Low Energy Costs Scenario					
Industry[a]	9.7	13.9	9.6	5.8	39.0
Buildings[a]	4.0	7.0	--	9.3	20.3
Transportation[a]	25.9	.1	.1	.1	26.2
Total demand[a]	39.6	21.0	9.7	15.2	85.5
Conversion losses[b]	9.7	4.8	--	34.8	49.3
Primary Input	49.3	25.8	9.7	50.0	134.8
2010, Moderate Energy Costs Scenario					
Industry[a]	10.0	6.9	12.6	3.1	32.6
Buildings[a]	2.9	3.4	--	6.3	12.6
Transportation[a]	19.4	.1	.1	--	19.6
Total demand[a]	32.3	10.4	12.7	9.4	64.8
Conversion losses[b]	5.8	.6	--	22.7	29.1
Primary Input	38.1	11.0	12.7	32.1	93.9
2010, High Energy Costs Scenario					
Industry[a]	8.7	6.2	10.7	2.6	28.2
Buildings[a]	2.2	2.5	--	4.8	9.5
Transportation[a]	14.0	.1	.1	--	14.2
Total demand[a]	24.9	8.8	10.8	7.4	51.9
Conversion losses[b]	3.2	.5	--	18.0	21.7
Primary Input	28.1	9.3	10.8	25.4	73.6
2010, High Economic Growth Scenario					
Industry[a]	14.2	9.6	17.5	4.4	45.7
Buildings[a]	3.7	4.6	--	8.6	16.9
Transportation[a]	26.9	.2	.2	.1	27.4
Total Demand[a]	44.8	14.4	17.7	13.1	90.0
Conversion Losses[b]	11.8	1.4	--	30.4	43.6
Primary Input	56.6	15.8	17.7	43.5	133.6

[a] Energy delivered to point of use in consuming sections.

[b] Conversion losses include losses during extraction, refining, production, transmission, and distribution.

[c] Includes electricity generated from coal, oil, gas, hydro, nuclear, geothermal, and other sources.

shifts in the composition of demand which have important implications for the economy. This is illustrated for the "base case" scenario in table 4. Given the framework of the analysis, these shares are determined by the price increases assumed for each source over the forecast period.

Table 4. Composition of Secondary Energy Demand, "Base Case" (percent)

	Industry		Buildings		Transportation		Total	
	1975	2010	1975	2010	1975	2010	1975	2010
Oil	27	31	32	23	97	98	51	50
Gas	43	21	45	27	3	1	31	16
Coal	19	39	1	0	0	1	7	20
Electricity	11	9	22	50	0	0	11	14
	100	100	100	100	100	100	100	100

The demand for gas by industry falls absolutely as well as proportionately, while the industrial demands for coal and, to a lesser extent, oil increase significantly. Although more electricity is demanded on an absolute basis, this increase does not keep pace with the increases in coal and oil demand, and electricity drops slightly as a proportion of total industrial energy demand. In the residential and commercial buildings sector the results are somewhat different. The demands for both oil and gas fall absolutely, leading to a large decline proportionately in each case. Since coal does not compete on any significant scale in this sector the decreases in oil and gas demand are compensated for by a large increase in electricity demand. In fact, under the conditions postulated for this scenario electricity is expected to account for half of all residential and commercial buildings energy consumption by 2010. Fuel shifts in the transportation sector are not particularly interesting since fuel choices are tightly constrained by technology and economics.[2] Looking finally at the composition of total demand, oil's share remains stable because the opposing trends in the industrial and buildings sectors cancel each other out. In 2010 the overall market share for gas is projected to be half of what it was in 1975. The market share for coal triples by 2010, at which time it exceeds the market share for gas. In spite of the large increase in the proportion of buildings' energy demand that is met from electricity, its share of the total market increases only slightly.

One of the demand panel's conclusions summarizes the implications of these projections for national energy policy:

> "The growth in energy use over the decades ahead can vary over an extraordinarily wide range, depending on the interaction between energy prices, GNP, policy decisions, the rate at which available technology is put into use, and the rate at which new technology is developed....There seem to be no unique, long-term relationships between energy growth and GNP growth, at least for the ranges of growth and price examined here, largely because of the many opportunities there are for increasing the efficiency of energy use. Policy and price as instruments of change can provide choices among a much broader range of possible futures than has generally been recognized. Since much of the nation's energy-consuming infrastructure will be replaced over the decades ahead, it will be possible to change the energy-consuming characteristics of this infrastructure without adding much to its initial cost. If the system chosen evolves slowly, there are unlikely to be any major adverse effects on employment, consumer choices, and perceived amenities, even for energy futures that are substantially different from those arrived at by extrapolating present trends" (NAS, 1979, p. 33).

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[2] The authors note that although new technological developments or policy decisions could increase the use of electric or alcohol-fueled vehicles and there could be a shift from petroleum to energy derived from coal and biomass sources, the net effect on total energy requirements will be minor.

V. Comments

The CONAES demand panel's report combines carefully thought-out narrative analyses together with results obtained from two large-scale economic models. By virtually confining their focus to 2010, however, the authors offer little insight into the nature of the transition implied by the 2010 projections.

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Appendix F

Summary of Stanford Alternative Energy Futures Study

I. Background

As reliance on large-scale engineering and economic models to analyze energy issues has increased, the influence of variables not amenable to some sort of quantitative description has become correspondingly more difficult to account for. A case in point is the attention paid to so-called socioeconomic factors,[1] occasionally ambiguous variables which figure strongly in decision-making but have not been adequately integrated into the analysis underlying many long-run energy projections. This lack of attention is not because modelers feel that these variables play insignificant roles, but rather because their models require rigorous (if incomplete) specifications within which it becomes awkward to incorporate them. Recognizing this problem, the Institute for Energy Studies at Stanford University began work which, in part, looked at how different sets of social variables may interact with technological, economic, and other factors to influence energy supply and demand in the decades ahead, as well as the economic, social, and environmental consequences that may be associated with different sets of decision criteria (value systems). Their results complement those of other energy studies and provide insight into an important, yet poorly understood, aspect of energy research.

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[1] Examples include centralized versus decentralized organization (social, political, or institutional), attitudes towards the tradeoff (if it exists) between environmental preservation and economic growth, and public perceptions of the risks associated with different energy sources and technologies.

II. Methodology

The Stanford/IES approach is summarized in the group's report as:

a. The broad range of values relevant to the problem were aggregated into two alternative value systems to "provide a foundation for describing relationships between socio-cultural variables and energy systems in future societies."

b. Four sectors of the economy (industry, transportation, residential and commercial buildings, and agriculture) were reviewed, with emphasis on energy intensive conversion devices and processes, in order to estimate the extent to which energy consumption could be reduced without adversely affecting the standard of living or the economy. National energy consumption estimates were derived consistent with the value systems and decision criteria considered important by the populations of the three scenarios.

c. Conventional and alternative electrical conversion technologies were similarly examined and allocated to electricity demand using the same criteria, as were natural energy resources.

d. The technology configurations, resource requirements, and degree of conservation implied by the results for each scenario were then evaluated in light of their impacts on the standard of living and on the environment. Conclusions were also drawn on the barriers to successful realization of future independence from imported energy.

In applying this methodology the authors were careful to recognize that real value systems are "often diffuse, mixed, and contradictory over time." The two alternative value systems used in the analysis are essentially composites which summarize two fundamental ways of thinking about the world. The question is then: given the percentages of the population whose views are roughly consistent with the two value systems, which of the various energy sources or alternatives will be considered most desirable and what changes in public laws and policies must occur to satisfy the constraints underlying the two scenarios?

The two sets of value systems were defined by outlining the views characteristic of each. For example, one value system places priority on economic growth, while the other places priority on minimizing adverse environmental impacts. It will be convenient to refer to these value-systems as "hard energy" and "soft energy" orientations,[2] although each system encompasses variables that are not generally considered in relation to energy.

Table 1. Definition of the Two Value Systems

Type 1 "Hard Energy" Orientation	Type 2 "Soft Energy" Orientation
1. Rationality in decision-making	1. Rationality in decision-making
2. Uses life-cycle costing to evaluate economic factors.	2. Uses life-cycle costing to evaluate economic factors.
3. Individualism	3. Interdependence
4. Humans over nature.	4. Humans within nature.
5. Competition/achievement	5. Cooperation
6. Unbounded material progress	6. Bounded material progress
7. Quantitative orientation	7. Qualitative orientation
8. Sequential rationalism	8. Heuristic rationalism
9. Outward material success	9. Inward success
10. Centralized organization	10. Decentralized organization

After completing the "value-system" analysis, the IEAS commissioned a series of runs using the Brookhaven Energy System Optimization Model (BESOM) to help identify inconsistencies involving complex interactions between the various parts of the energy system. The results of this exercise were then folded back into the initial analysis.

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[2] This terminology is used with some reluctance because it may conjure up stereotypic images of "insensitive industrialists" on the one hand and "solar gurus" on the other, both of which are inappropriate interpretations.

III. Assumptions

The authors point out that "since our purpose is to simulate the effects of two viewpoints that arise from fundamental sets of values, our scenarios are defined in terms of the dominant social paridigms assumed to prevail in future society."[3] These paridigms, in turn, determine the alternative levels and compositions of future energy supply and demand. Since major components of each of the four end-use sectors were examined independently, the economic assumptions underlying the study cannot be easily summarized in terms of highly aggregated measures such as projected GNP, personal income, and the like. Consequently, readers are referred to the IES report for information on the detailed assumptions made for each of the sub-sectors and the rest of this section will concentrate on defining the scenarios in terms of the socioeconomic factors outlined in table 1.

These scenarios are defined primarily according to the proportions of the population assumed to hold views that are consistent with the two value-systems at different benchmark years in the future.[4] In table 2 it can be seen that scenarios I and III represent situations in which one of the two value-systems penetrate the population to an extreme. In scenario II the value-systems penetrate to an equal degree and society as a whole is basically "ambivalent." It should be noted that none of the scenarios can be considered a "base case," although the authors imply that the proportions assumed in scenario I are probably closer to the proportions existing today than the proportions in scenarios II and III.

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3. Social paridigm is defined as "the basic way of perceiving, thinking, valuing, and doing associated with a particular vision of reality."

4. This is not meant to imply that each individual always acts according to one of the value-systems, but rather that on the average individuals, taken together as a whole population, act as if some percentage hold Type 1 values and the remainder hold Type 2 values.

Table 2. Assumed Proportions of the Total U.S. Population Holding Type 1 ("Hard Energy") and Type 2 ("Soft Energy") Views by Scenario (percent)

	1990		2025	
Scenario	Type 1	Type 2	Type 1	Type 2
I	95	5	95	5
II	75	25	50	50
III	50	50	10	90

In addition, the proportions assumed for each scenario were taken to be consistent with the following characteristics.

Table 3. Additional Characteristics of the Scenarios[a]

	Scenarios		
	I	II	III
Level of Material Amenities	H	H	L
Nonrenewable energy consumed	H	M	L
Industrial decentralization	L	L	M
Proportion of environmental and social costs internalized in market	L	M	H
Considerations of noneconomic quality of life	L	M	H

[a] H = High, M = Medium, L = Low

Finally, certain assumptions are held constant across the three scenarios. That is, the development of energy supply and demand systems must take place under three constraints:

a) U.S. reliance on imported petroleum must be reduced rapidly.

b) Technological and social changes must occur in a smooth and continuous fashion.

c) The amenities enjoyed by individuals, viewed within the context of their value-systems, and the standard of living which these goods imply in the aggregate, must equal or exceed present levels.

IV. Projections

Within the framework used by the IES group the question of interest is: How do variations in the penetration of the two value systems alter the aggregate levels, as well as the composition, of future energy demands and supplies? It is useful to start by looking at the secondary energy demands of each end-use sector, later adding the primary resources used by utilities to generate electricity to find primary energy balances. Table 4 summarizes the results obtained for the industrial sector, which indicate that aggregate industrial energy demand decreases as the proportion of the population with "soft energy" orientations increases. It will be seen that this result holds for all of the end-use sectors, as well as for total primary energy. In terms of the composition of industrial demand, the population mix assumed for scenario I apparently prefers coal and electricity while the mix assumed for scenario III seems to prefer gas. The scenario II results are a compromise between these two extremes. It is significant that, in all three scenarios, liquids demand drops to zero or near-zero by 2025. Tables 5, 6, and 7 present analogous results for the transportation, residential and commercial buildings, and agriculture sectors, respectively.

Table 4. Industrial Demand for Secondary Energy
(quads)

		Scenario I		Scenario II		Scenario III	
	1977[a]	1990	2025	1990	2025	1990	2025
Liquids[b]	7.0	4.7	0.0	4.5	0.0	3.2	0.2
Gases[b]	8.6	8.0	1.0	9.0	4.9	8.8	6.8
Coal	3.6	7.6	36.3	5.2	23.2	2.2	5.8
Electricity[c]	2.6	2.2	3.8	2.0	2.3	1.6	1.2
TOTAL	21.8	22.5	41.1	20.7	30.4	15.8	14.0

Note: In the Stanford study industrial energy demand is satisfied by four sources--liquids, gases, solids and "any form." For purposes of this table (and table 9), demand for "any form" has been allocated to the other fuels by using the study's aggregate supply figures for each fuel and subtracting demand for each fuel accounted for by other sectors of the economy. The remainder is used as the industrial energy demand figure.

[a] Source: U.S. Department of Energy, *Monthly Energy Review*, January 1979, as cited in *Alternative Energy Futures*.

[b] These generic categories are used because in some scenarios coal and biomass liquids and biomass gases are supplied to meet the demand.

[c] Measured as delivered electricity.

Table 5. Transportation Demand for Secondary Energy
(quads)

		Scenario I		Scenario II		Scenario III	
	1977[a]	1990	2025	1990	2025	1990	2025
Liquids[b]	19.1	20.0	21.3	20.0	20.3	18.1	12.4
Gases[b]	0.6	0.0	0.0	0.0	0.0	0.0	0.0
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity[c]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	19.7	20.0	21.3	20.0	20.3	18.1	12.4

[a,b,c] See notes for table 4.

Table 6. Residential and Commercial Buildings Demand for Secondary Energy (quads)

		Scenario I		Scenario II		Scenario III	
	1977[a]	1990	2025	1990	2025	1990	2025
Liquids[b]	7.1	4.2	2.4	4.1	2.0	3.8	1.5
Gases[b]	7.5	7.1	6.7	6.9	4.6	6.5	3.3
Coal	0.2	0.4	0.2	0.4	0.2	0.4	0.1
Electricity[c]	3.9	5.2	5.0	4.6	4.4	4.3	3.2
TOTAL	18.7	16.9	14.3	16.0	11.2	15.0	8.1

[a,b,c] See notes for table 4.

Table 7. Agricultural Demand for Secondary Energy (quads)

		Scenario I		Scenario II		Scenario III	
	1977[a]	1990	2025	1990	2025	1990	2025
Liquids[b]	--	1.5	1.6	1.4	1.3	1.3	1.1
Gases[b]	--	1.6	1.7	1.4	1.2	1.2	0.8
Coal	--	0.1	0.1	0.1	0.1	0.1	0.1
Electricity[c]	--	0.6	0.6	0.5	0.4	0.5	0.4
TOTAL	--	3.8	4.0	3.4	3.0	3.1	2.4

[a] Comparable historical data not available for this sector.

[b,c] See notes for table 4.

To get a clear picture of energy demand in the future it is necessary to know something about the primary energy sources used to generate electricity. What role will renewable resources and "new" technologies play? To what extent will oil and gas be phased out? The results in table 8 indicate that the answers to these and related questions are largely dependent on the scenario under consideration, although no liquids or gases are used to generate electricity by 2025 in any of the scenarios. Coal remains an important utility fuel throughout the forecast in scenario I, but its use drops off by nearly 70 percent in scenario II and coal is

Table 8. Sources of Delivered Electricity[a]
(quads)

	1977	Scenario I 1990	 2025	Scenario II 1990	 2025	Scenario III 1990	 2025
Coal	3.4	4.3	4.2	3.9	1.3	3.4	0.0
Oil/Gas	2.3	1.3	0.0	1.1	0.0	0.8	0.0
Geothermal	0.0	0.1	1.8	0.1	1.8	0.1	1.2
Nuclear	0.9	1.9	1.8	1.5	1.3	0.0	0.0
Solar Electric	0.0	0.0	0.0	0.0	1.3	1.4	2.5
Hydropower	0.7	1.4	2.4	1.4	2.0	1.5	1.5
TOTAL	7.3	9.0	10.1	8.0	7.6	7.2	5.2

[a] Converted from primary forms using following efficiencies--oil/gas -.42, coal -.40, all other -.33.

Source: Alternative Energy Futures.

completely discontinued in scenario III. Geothermal makes a significant contribution in all cases, particularly in scenarios I and II, while nuclear is also strong in I and II, but falls out in III. Solar electric is introduced on a meaningful scale by 1990 in scenario III and 2025 in scenario II. Generation from hydropower grows in all scenarios, especially I. In thinking about these utility demand shifts, as well as the shifts occurring in other sectors, it is helpful to relate them to the characteristics of the value-systems underlying each scenario. The decline of coal demand in scenarios II and III, for example, seems to be a result of the increased value of environmental quality that is characteristic of these scenarios.

As suggested at the beginning of this section, by combining the sectoral demand for liquids, gases, and coal with the utility demand for primary energy used to generate electricity it is possible to get estimates of aggregate primary energy demand.[5] These estimates can then be compared with supply estimates to arrive at aggregate energy balances for each scenario in each time period, as shown in table 9.

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[5] Strictly speaking, the results reported below in table 9 are for "quasi primary" energy since coal liquids are included as a supply source (with appropriate adjustments made for coal conversion losses) and refining losses have been taken out of liquids supply.

Table 9. Aggregate Demand for and Supply of Primary Energy (quads)

		Scenario I		Scenario II		Scenario III	
	1977[a]	1990	2025	1990	2025	1990	2025
Demand							
Liquids	37.1	32.0	25.3	31.4	23.6	27.3	15.2
Gases	19.9	18.3	9.4	18.7	10.7	17.4	10.9
Coal	14.0	18.8	47.0	15.3	26.7	11.3	6.0
Other[b]	5.2	10.2	17.8	9.0	18.9	9.0	15.6
TOTAL	76.3	79.3	99.5	74.4	79.9	65.0	47.7
Supply							
Liquids							
Domestic oil	18.9	22.0	11.0	22.0	9.7	22.0	8.3
Imported oil	18.1	12.9	0.0	12.9	0.0	8.3	0.0
Coal liquids	--	0.6	9.9	0.0	6.3	0.0	0.0
Biomass	--	0.0	0.0	0.0	8.6	0.0	7.8
Oil Shale	--	0.0	5.6	0.0	0.0	0.0	0.0
Petroleum refining losses[c]	--	-3.5	-1.2	-3.5	-1.0	-3.0	-0.9
TOTAL Available	37.1	32.0	25.3	31.4	23.6	27.3	15.2
Gases							
Domestic NG	18.9	18.0	8.0	18.0	7.7	16.7	7.3
Imported NG	1.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	--	0.3	1.4	0.7	3.0	0.7	3.6
TOTAL Available	19.9	18.3	9.4	18.7	10.7	17.4	10.9
Coal							
Solids	14.0	19.8	64.4	15.3	37.8	11.3	6.0
Less conversion	--	-1.0	-17.4	0.0	-11.1	0.0	0.0
TOTAL Available	14.0	18.8	47.0	15.3	26.7	11.3	6.0
Other							
Geothermal	0.1	0.4	5.3	0.4	5.3	0.4	3.7
Nuclear	2.7	5.7	5.4	4.3	3.8	0.0	0.0
Solar Electric	--	0.0	0.0	0.0	3.8	4.2	7.5
Hydropower	2.5	4.1	7.1	4.3	6.0	4.4	4.4
TOTAL	5.2	10.2	17.8	9.0	18.9	9.0	15.6
TOTAL SUPPLY	76.3	79.3	99.5	74.4	79.9	65.0	47.7

[a] See table 4 for source.

[b] Represents primary electricity. See "Other" at bottom of table for components.

[c] Refining losses assured to equal 11 percent of all oil for 1977, already netted out from domestic and imported oil rows.

V. Comments

The Standford/IES Alternative Energy Futures group has made substantial progress towards developing an analytical framework within which it is possible to learn more about the interrelations between social, economic, and energy variables. The strongest aspects of this contribution are probably the definition of the two value-systems using relevent socioeconomic variables and the effort to relate the broad trends suggested by their forecasts to these value-systems. A weaker aspect, though, is the lack of convincing evidence on the ties between specific results and the scenario assumptions. In addition, the analysis was performed in an extremely disaggregated manner and it is not clear, in spite of the use of the Brookhaven model, how the various parts of the work were brought together into a consistent whole.

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Appendix G

Summary of RFF/SEAS Energy Projections

I. Background

A comprehensive analysis of alternative economic growth paths through 2025 and their implications for the environment, resources and the national economy carried out at Resources for the Future (RFF) includes projections of the U.S. demand, production, and international trade of various fuels.[1] These projections were developed in light of evidence on prices, elasticities, technological change, cumulative energy resource availability, and other factors. Although the study was published only in 1980, the underlying research and historical data embody few developments beyond the mid-1970s. Despite this datedness, the comprehensive nature of the study and of its methodological structure prompts its inclusion in this review.

II. Methodology

The study's projections were generated using the RFF Strategic Environmental Assessment System (RFF/SEAS), an augmented version of the University of Maryland's dynamic Interindustry Forecasting model (INFORUM). In developing the SEAS Framework, the following capabilities were integrated into INFORUM to capture the impacts of economic, technological, and policy variables on energy markets:

A. Use of relative energy prices and price elasticites to alter energy demands, capital requirements, and GNP growth.

B. Application of technology change assumptions to modify current and capital account flows.

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[1] Ronald G. Ridker and William D. Watson. 1980. To Choose A Future: Resource and Environment Consequences of Alternative Growth Paths (Baltimore, Johns Hopkins University Press for Resources for the Future).

C. Sectoral disaggregation to provide detail on industrial output.

D. Calculation of costs for pollution abatement.

E. Calculation of energy supply and demand mixes in light of trends in fuel availability and energy supply technologies.

F. Exogenous specification of import and stockpile levels for selected minerals, allowing, for instance, the examination of impacts resulting from a supply disruption.

III. Assumptions

The major macroeconomic assumptions adopted for the base-case scenario are listed in table 1.

Table 1. Key Macroeconomic Assumptions for the Base Case

	1975	1985	2000	2025
Population (millions)	213.9	235.7	264.4	303.8
Labor force (millions)	94.8	--	124.3	139.1
GNP (billion 1971 dollars)	1108.0	1574.6	2428.5	4243.4
GNP per capita (1971 dollars)	5180.0	6680.0	9184.0	13968.0

IV. Projections

Table 2 presents the base-case projections of net energy consumption by end-use sectors through 2025. When coal liquids and gases are measured according to coal requirments and electricity is measured according to the primary fuels (or primary equivalents of alternative technologies) used to generate it, as shown in table 3, a measure of primary (or "gross") energy consumption is obtained. Table 4 compares the resulting consumption projections to projections of supply from major fuels and technologies.

Table 2. Sectoral Energy Demands by Fuel, Base Case (quads)

	1975[a]	1985	2000	2025
Industrial[b]				
Oil	8.0	11.8	16.8	30.2
Gas	9.6	10.0	8.7	15.6
Coal	4.7	4.9	6.8	9.9
Electricity[c]	2.6	4.1	5.6	9.0
TOTAL	24.9	30.8	37.9	64.7
Commercial				
Oil	2.4	3.0	4.0	3.1
Gas	2.4	2.5	2.0	1.2
Coal	0.0	0.0	0.0	0.0
Electricity	1.3	2.2	4.0	8.0
Solar	0.0	0.0	0.6	3.2
TOTAL	6.1	7.7	10.6	15.5
Residential				
Oil	3.6	3.1	2.9	2.1
Gas	5.1	4.2	3.0	0.8
Coal	0.4	0.0	0.0	0.0
Electricity	2.1	3.5	4.8	5.5
Solar	0.0	0.0	0.6	3.2
TOTAL	11.2	10.8	11.3	11.6
Transportation				
Oil	17.2	20.4	24.4	33.9
Gas	0.8	0.9	1.1	1.5
Electricity	0.0	0.0	0.2	2.1
TOTAL	18.0	21.3	25.7	37.5
Other				
Electricity[d]	0.6	1.1	1.6	3.0
TOTAL net consumption	60.8	71.7	87.1	132.3

[a] These are "projections" calculated using the model, rather than historical data.

[b] Includes agriculture, mining, construction, and manufacturing.

[c] Electricity delivered to consumers by utilities, computed at 3412 BTU per kWh.

[d] Electricity consumed by electric utilities

Table 3. Primary Energy Consumption by Electric Utilities
(quads)

	1975[a]	1985	2000	2025
Oil	2.9	4.5	1.3	0.0
Gas	4.2	4.5	1.3	0.0
Coal	8.7	14.4	14.0	17.6
Hydro	2.9	3.0	3.2	3.3
Nuclear, LWR	2.2	5.8	20.2	19.7
Nuclear, breeder	0.0	0.0	2.5	16.5
Nuclear, fusion	0.0	0.0	0.0	4.7
Geothermal	0.0	0.0	1.1	2.9
TOTAL	20.9	32.2	43.6	64.7

[a] See footnote for table 2.

Table 4. Demand/Supply Balances for Primary Energy (quads)

	1975[a]	1985	2000	2025
Demand				
Oil	34.1	42.8	49.4	53.3
Gas	22.1	22.1	16.1	18.7
Coal[b]	13.8	19.3	20.8	36.3
Other[c]	5.1	8.8	28.2	63.0
TOTAL	75.1	93.0	114.5	171.3
Supply				
Domestic				
Oil	20.2	16.5	11.2	6.1
Natural gas	21.4	17.2	12.0	5.6
Coal	15.5	21.7	23.7	46.3
Shale Oil	0.0	0.0	0.0	9.5
Hydro	2.9	3.0	3.2	3.3
Geothermal	0.0	0.0	1.1	2.9
Solar (space cond.)	0.0	0.0	1.2	6.4
Nuclear, LWR	2.2	5.8	20.2	19.7
Nuclear, breeder	0.0	0.0	2.5	16.5
Nuclear, fusion	0.0	0.0	0.0	4.7
TOTAL	62.2	64.2	75.1	121.0
Net Imports				
Petroleum	13.9	26.3	38.1	47.2
Natural gas	0.7	4.9	4.1	13.1
Coal	-1.8	-2.4	-2.9	-10.0
TOTAL supply	75.0	93.0	114.4	171.3

[a] See footnotes for table 2.

[b] Figure for 2025 includes demand for liquified and gasified coal.

[c] Includes primary sources for electrical generation and solar space conditioning.

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